Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network

Submitted by Western Power

29 March 2012

Economic Regulation Authority
WESTERN AUSTRALIA

Important Notice

This document has been compiled in good faith by the Economic Regulation Authority (**Authority**). The document contains information supplied to the Authority from third parties. The Authority makes no representation or warranty, express or implied, as to the accuracy, completeness, reasonableness or reliability of the information supplied by those third parties.

This document is not a substitute for legal or technical advice. No person or organisation should act on the basis of any matter contained in this document without obtaining appropriate professional advice. The Authority and its staff members make no representation or warranty, expressed or implied, as to the accuracy, completeness, reasonableness or reliability of the information contained in this document, and accept no liability, jointly or severally, for any loss or expense of any nature whatsoever (including consequential loss) arising directly or indirectly from any making available of this document, or the inclusion in it or omission from it of any material, or anything done or not done in reliance on it, including in all cases, without limitation, loss due in whole or part to the negligence of the Authority and its employees.

This notice has effect subject to the *Competition & Consumer Act 2010 (Cwlth),* the *Fair Trading Act 1987 (WA) and the Fair Trading Act 2010 (WA)*, if applicable, and to the fullest extent permitted by law.

Any summaries of the legislation, regulations or licence provisions in this document do not contain all material terms of those laws or obligations. No attempt has been made in the summaries, definitions or other material to exhaustively identify and describe the rights, obligations and liabilities of any person under those laws or licence provisions.

A full copy of this document is available from the Economic Regulation Authority website at www.erawa.com.au.

For further information, contact:

Economic Regulation Authority
Perth, Western Australia
Phone: (08) 6557 7900

Contents

List of Tables

List of Figures

DRAFT DECISION

Background

1. On 30 September 2011, Western Power submitted proposed revisions to its access arrangement for the Western Power Network (**proposed revised access arrangement**)[1] to the Economic Regulation Authority (**Authority**). The proposed revised access arrangement relates to the third access arrangement period, the five year period from 1 July 2012 to 30 June 2017. The revised access arrangement was submitted in accordance with the requirements of section 4.48 of the *Electricity Networks Access Code 2004* (**Access Code**) and the revisions submission date specified in the current access arrangement.[2]

2. The proposed revised access arrangement and revised access arrangement information are available on the Authority's website.[3]

3. The role of the Authority is to determine whether Western Power's proposed revised access arrangement:
   - meets the Code objective of promoting economically efficient investment in and operation and use of electricity networks and services of networks in Western Australia, in order to promote competition in markets upstream and downstream of the networks; and
   - complies with the requirements of the Access Code.

4. The Authority invited submissions from interested parties on the proposed revised access arrangement by publishing a notice on 7 October 2011. The closing date for submissions was 21 November 2011.

5. Following receipt of an errata sheet from Western Power on 25 October 2011, the Authority decided to extend the deadline for submissions to 5 December 2011 to give interested parties more time to take account of the new information.

6. To assist interested parties in understanding the proposed revised access arrangement, the review process and some of the significant issues to be addressed by the Authority in determining whether to approve or not approve the proposed revised access arrangement, the Authority published an issues paper on 7 November 2011. On 14 November 2011, the Authority held a public forum on the proposed revised access arrangement and the Authority's Issues Paper.

---

1 Western Power, 30 September 2011. *Proposed revisions to the Access Arrangement for the Western Power network*; hereafter cited as ("Proposed Revised Access Arrangement").

Western Power, 30 September 2011. *Access Arrangement Information for 1 July 2012 to 30 June 2017*; hereafter cited as ("Revised Access Arrangement Information").

2 The revisions submission date is specified under the current access arrangement as 1 October 2011 (Western Power, 24 December 2009. *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, clause 1.5, p. 1).

3 Economic Regulation Authority website: http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

7. Submissions were received from 36 interested parties and published on the Authority's website.[4] A list of interested parties who made a submission is included in Appendix 1.

8. Under section 4.12 of the Access Code, the Authority must consider any submissions made on the proposed revised access arrangement (before the closing time) and must make a draft decision either:

    1) to approve the proposed revised access arrangement; or

    2) to not approve the proposed revised access arrangement, in which case the Authority must in its reasons provide details of the amendments required before the Authority will approve it.

9. Western Power's current access arrangement applies until a new proposed access arrangement is approved by the Authority.

Western Power's Proposal

10. Western Power has proposed substantial increases in reference tariffs in the first year of the third access arrangement period of 16.4 per cent plus CPI followed by increases of approximately 11 per cent plus CPI for the following years.

11. The proposed increases in reference tariffs result mainly from:

    - full recovery of $967 million (dollars at 30 June 2012) of revenue which was deferred in the second access arrangement, due to a change in the treatment of capital contributions, to minimise price shocks;
    - a substantial increase in operating expenditure in real terms over AA3, with the forecast level of operating expenditure in 2016/17 (the final year of the third access arrangement period) around 32 per cent higher for the transmission network and 18 per cent higher for the distribution network than the estimated level in 2011/12;
    - a capital expenditure program of $5.8 billion compared with $4.3 billion expenditure incurred during the preceding five year period;
    - the addition of $244.4 million of capital investment into the capital base that the Authority had previously disallowed as inefficient expenditure; and
    - an increase in the rate of return from 7.98 per cent (real, pre-tax) for the current access arrangement to 8.82 per cent (real, pre-tax).

12. Western Power has also proposed:

    - a significantly different service performance incentive scheme;
    - the inclusion of three new bi-directional (entry and exit) reference services;
    - a revised applications and queuing policy which makes significant changes to the current single queue mechanism and instead grouping applicants affected

[4] Economic Regulation Authority website: http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

by the same network constraints together to enable development of joint network solutions;

- various methodological changes for the calculation of target revenue; and
- a new charging scheme for distribution low voltage connections.

13. Section 6.37A of the Access Code provides for Western Power's target revenue to include an amount of tariff equalisation contributions which comprises an amount levied on users of the Western Power Network to finance amounts paid to Horizon Power for the provision of electricity services in areas not serviced by the Western Power network. The State Government is yet to gazette any amounts for the tariff equalisation contribution beyond 2011/12 so Western Power has based its target revenue requirement on forecasts provided in the State Budget indexed in line with inflation. The total forecast for the third access arrangement period is $906.9 million (in dollar values at 30 June 2012).

Summary of Key Points

14. The following paragraphs 15 to 50 summarise some of the key points included in the Authority's draft decision. This summary is not a comprehensive statement of the Authority's reasoning. The Authority's full reasoning for its draft decision is set out in paragraph 61 onwards.

15. In making its assessment of Western Power's forecast target revenue requirement, the Authority has had regard to:

    - Western Power's performance during the first and second access arrangements:
        - significant under expenditure during the second access arrangement period compared with the forecast costs approved by the Authority in its final decision in relation to the second access arrangement period;
        - good service standard performance during the second access arrangement period; and
        - notwithstanding the improvements that have been made during the second access arrangement period, the ongoing deficiencies in relation to Western Power's management and governance processes for undertaking operating and capital activities.
    - Significant increases in Western Power's expenditure forecast for the third access arrangement period compared with actual expenditure during the second access arrangement period.
    - Western Power's management of its wood poles:
        - an outstanding Energy Safety Order in relation to the condition of Western Power's wood poles;
        - the 2011 Asset System Review[5], which identified issues with Western Power's asset information; and

[5] GHD Asset Management System Review Final Report, October 2011.

  - a recent Parliamentary inquiry into Western Power's management of wood poles which has highlighted serious weaknesses in Western Power's asset management procedures including its management of asset data.
- Efficiency of operating expenditure:
  - a comparison of Western Power's costs with other network service providers.
- Proposed methodological changes by Western Power compared with previous access arrangements all resulting in an increase to forecast target revenue.

Western Power's performance

16. Western Power's total capital expenditure during the second access arrangement is estimated to be 39 per cent ($1.2 billion) lower than the $3.1 billion approved by the Authority. The major areas of under expenditure have been capacity expansion and customer driven capital expenditure, particularly on the transmission network. Notwithstanding this, Western Power has met or exceeded 34 of the 38 service level benchmarks over the first two years of the second access arrangement and, over this time, network service levels have shown an improvement from earlier years.

17. While there are a number of reasons for this underspend, including the impact of the global financial crisis on electricity demand and reduced new customer connections, the fact that Western Power still exceeded its service level targets in spite of substantial capital expenditure reductions indicates there was some inefficiency in its approved capital expenditure forecast for the second access arrangement period.

18. In previous access arrangement reviews the Authority has identified serious weaknesses in relation to Western Power's planning, design and governance of investment expenditure and inefficiencies in cost estimation processes. These findings led to the Authority excluding $261 million ($ real as at 30 June 2009) of capital expenditure incurred in the first access arrangement period from Western Power's capital base.

19. Western Power notes in its proposed revised access arrangement that, in response to the criticism of the Authority and the Authority's technical adviser, it "sharpened" its focus on initiatives to improve strategic planning, delivery and compliance processes.[6] As a result, a number of capital projects included in the forecasts for the second access arrangement period were deferred or cancelled.

20. The Authority's technical consultant has observed that processes for managing the development and implementation of capital expenditure and operating expenditure projects and programs have improved since the second access arrangement review. However, the Authority's technical consultant notes:

> … some risk management processes are in place (as we would expect) but they are relatively unstructured, and tend to be qualitative and subjective. While risk assessments are required for all capital projects and programs, they appear to be used primarily to support business cases rather than as an integral part of the planning and

[6] Western Power Access Arrangement Information p. 62.

prioritisation process. We think risk assessments could be better structured and used more effectively as a tool for prioritising expenditure.[7]

Western Power recognises the deficiencies in its current risk assessment and prioritisation processes and is taking steps to address them. Good industry practice is for asset maintenance and replacement activities to be prioritised across asset classes using a condition based risk management approach. Each asset is given a “health index” based on its condition weighted by a quantitative assessment of the risk to the business should the asset fail. Assets are prioritised for maintenance on the basis of their health indices. Western Power does this for some individual asset classes but has still to extend this approach to directly compare the risk of asset failure across different asset classes.[8]

… further improvements are possible particularly in relation to the development and assessment of alternative options for expenditure projects and programs. In addition, Western Power still lacks a quantitative risk assessment tool and the application of risk management techniques to the prioritisation of expenditure appears unstructured and subjective. Western Power is planning to improve its risk management processes and is purchasing new asset management software. However, the extent to which it is planning to further integrate risk assessment into its expenditure planning processes and to implement a maintenance management system based on condition based risk management principles consistent with industry best practice remains unclear.[9]

Management of data on the existence and condition of assets is a problem for Western Power and this continues to adversely impact the efficiency with which programs and projects are implemented. While some stakeholders appear to see this as a problem of data accuracy, the timeliness with which existing databases are updated and the availability of current asset information to staff managing and implementing field work appears to be a more significant issue. The ongoing reliance on legacy asset information databases with limited functionality and accessibility is part of the problem; these systems are currently being replaced. However, we think insufficient resources are being applied to the updating of asset data and consider that, unless this problem is addressed effectively, Western Power will not fully capture the benefits of its substantial investment in replacement asset information systems and databases. We have also seen little evidence of how Western Power plans to leverage these new information technology (IT) systems to improve the efficiency of its service delivery. We note, in particular, that such efficiency gains have not been allowed for in Western Power’s expenditure forecasts.[10]

21. Whilst the Authority notes the improvements in processes identified by its technical consultant, it is concerned there are still areas of weakness, particularly in relation to risk management and asset information. Potentially these weaknesses may lead to inefficient investment decisions.

---

7 March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, p. 23.

8 March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, p. 23.

9 March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, p. 1.

10 March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, p. 1.

Capital Expenditure[11]

Capacity Expansion and Customer Driven Expenditure

22. The Authority's technical adviser has identified $465 million in Western Power's forecasts for capacity expansion and customer driven expenditure which it considers is potentially overstated. The reasons for this include:

- specific projects which could be deferred;
- inefficiencies in specific projects;
- forecast increases compared to historical levels which are not adequately supported; and
- reductions in the demand forecast since the expenditure forecasts were prepared which would enable capacity expansion projects to be deferred.

23. Capacity expansion and customer driven capital expenditure, are subject to an investment adjustment mechanism which ensures that Western Power's target revenue is adjusted at the next access arrangement review for any forecasting error in relation to such expenditure. Expenditure higher than forecast can only be recovered to the extent that it is demonstrated to be efficient expenditure.

24. Given that any capacity expansion or customer driven capital expenditure overspend that meets efficiency requirements can be recovered in the fourth access arrangement period, and given the significant capital underspend compared to forecast during the second access arrangement period, the Authority considers it prudent for the approved capital expenditure for the third access arrangement to be conservative. There will therefore be less likelihood that customers will be asked to pay more during the third access arrangement than needed to fund the actual capital expenditure requirement, and the incentive on Western Power to deliver only an efficient level of capital expenditure is likely to be greater as actual capital expenditure will be subject to more intense ex post scrutiny if it is higher than the forecast approved by the Authority.

25. Consequently the Authority has accepted all the recommendations of its technical consultant and reduced Western Power's capital expenditure forecasts accordingly. If Western Power needs to spend more than the approved forecast then, provided it can be demonstrated to be efficient, the additional capital expenditure will be allowed for at the time of the fourth access arrangement review. Alternatively, the provisions of the Access Code enable Western Power to apply to the Authority at any time for pre-approval of capital expenditure forecasts.

Wood Poles

26. The poor condition of its wood pole population poses a high risk for Western Power because of the risk to public safety from unassisted wood pole failures and the potential for such failures to start bush fires that cause extensive property damage. Western Power's wood pole failure rate is significantly higher than other Australian distribution network service providers.

[11] The Authority's detailed reasoning in relation to forecast capital expenditure is set out in paragraphs 519 to 588 of this Draft Decision.

27. Western Power is proposing to significantly increase its wood pole replacement and reinforcement rates during the third access arrangement period and has included forecast capital expenditure of $748 million. Based on its current assessment of the condition of the wood pole population, Western Power considers it will take 20 years of elevated investment before it can reach a sustainable rate of replacement. Western Power has considered more aggressive timescales but considers the 20 year management plan is the most achievable approach.

28. In September 2009 Western Power was issued with an Order by EnergySafety which required, amongst other things, that all unsupported rural wood poles which do not comply with required standards be replaced or reinforced by 2015. This Order followed EnergySafety audits into Western Power's management of its distribution wood pole population that were undertaken in 2007 and 2009.

29. The Authority understands that EnergySafety considers Western Power's proposed wood pole management program is inadequate and that Western Power's preferred investment approach does not fully meet the Order's requirements.

30. Western Power's unassisted wood pole failure rate has also been the subject of a recent inquiry by the Standing Committee on Public Administration of the Legislative Council of the Western Australian Parliament.[12] The report of the Legislative Council's Standing Committee on Public Administration and the asset management review[13] undertaken for the Authority by GHD were both critical of aspects of Western Power's management of its wood pole replacement program.

31. The Authority notes that the level of wood pole renewal and replacement required in order to comply with the Safety Order is a matter for Western Power to resolve with the technical regulator, EnergySafety and is not for the Authority to determine.

32. The Authority's technical adviser considers that improvements in the efficiency with which wood pole inspections are undertaken and wood pole replacements are implemented are available, particularly if Western Power successfully addresses issues related to records management. However, the Authority considers any efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in the actual expenditure.

33. The Authority is aware that another network service provider has carried out an evaluation comparing steel and wood poles and, in its particular situation, established that steel poles had a lower life cycle cost and provided additional benefits compared with wood poles. The Authority expects that Western Power has undertaken similar analysis.

34. Potentially the investment needs for wood pole management may change as Western Power further develops its understanding of what is required. To ensure that Western Power is incentivised to do this in an efficient manner, the Authority has decided that, for the third access arrangement period, expenditure relating to wood pole management should be subject to the investment adjustment mechanism. This will then enable expenditure higher than forecast to be recovered, to the extent that it is demonstrated to be efficient expenditure, and will provide Western Power with a return on that investment from the date it is incurred. Alternatively, the provisions of

---

12 Unassisted Failure: Report 14, Standing Committee on Public Administration, Report 14, Legislative Council, Parliament of Western Australia, January 2012.

13 GHD Asset Management System Review Final Report October 2011.

the Access Code enable Western Power to apply to the Authority at any time for pre-approval of capital expenditure forecasts. All of these provisions ensure Western Power is not constrained to only spend what is allowed in the current forecast.

IT Expenditure

35. Contrary to the overall underspend in capital expenditure during the second access arrangement period, expenditure in relation to information technology was significantly higher than forecast and Western Power is proposing further substantial increases in the third access arrangement period. Based on advice from its technical adviser, the Authority does not consider the increases in expenditure have been adequately justified and has reduced the forecast expenditure for the third access arrangement period to be in line with actual expenditure during the second access arrangement period.

Operating expenditure[14]

36. As is the case of capital expenditure, Western Power's operating expenditure during the second access arrangement period has been significantly lower than the forecasts approved by the Authority. Western Power's forecasts for the third access arrangement period include significant increases above the actual expenditure during the second access arrangement period.

37. The Authority has paid particular attention to ensuring an efficient level of base operating expenditure and only legitimate increases above that are included in the forecast for the third access arrangement period.

38. The Authority's review of operating expenditure, which was assisted by its technical adviser, has identified $95 million of inefficient expenditure relating to specific items which have been removed from the operating expenditure forecasts.

39. Benchmarking by the Authority's technical consultant has shown that Western Power's operating expenditure performance is relatively poor compared with its Eastern State counterparts. This would suggest there is significant opportunity to make further efficiency gains. The Authority also notes that Western Power's business case for its proposed strategic program of works, which is expected to cost more than $132 million over a period of five years, was justified on the basis that it would lead to efficiency gains, yet Western Power has not included these efficiencies in its forecast operating costs.

40. The Authority considers annual operating cost efficiencies of between 2 and 3 per cent could be achieved. For the purposes of the draft decision the Authority has assumed 2 per cent.

Return on Regulated Capital Base[15]

41. Western Power has proposed a higher weighted average cost of capital (**WACC**) for its regulated capital base than the WACC approved for the second access

[14] The Authority's detailed reasoning in relation to forecast operating expenditure is set out in paragraphs 202 to 363 of this Draft Decision.

[15] The Authority's detailed reasoning in relation to the return on the regulated capital base is set out in paragraphs 608 to 888 of this Draft Decision.

arrangement period. The Authority does not consider this to be consistent with the prevailing rates for a business of its type and has adjusted it accordingly.

42. The Authority has reviewed the debt risk premium and adjusted it to be in line with a credit rating of A- (compared with the previous BBB+) which more accurately reflects an electricity network service provider's risk profile.

43. The Authority has also adopted a post tax WACC which is consistent with the Access Code requirements and to be in line with the practice adopted by nearly all regulators in Australia recognising that the use of a pre-tax WACC tends to over compensate service providers for their tax liabilities.

Methodological changes for assessing target revenue

44. In its proposed revised access arrangement, Western Power has included a number of new modelling methodologies and assumptions. The Authority notes that all of these changes proposed by Western Power result in an increase to target revenue.

Capital expenditure previously disallowed as inefficient[16]

45. The Authority excluded $261 million ($ as at 30 June 2009) of capital expenditure incurred in the first access arrangement period from Western Power's opening capital base for the second access arrangement period. This was as a result of weaknesses the Authority identified in relation to Western Power's planning, design and governance of investment expenditure and inefficiencies in cost estimation processes.

46. Despite the fact that Western Power acknowledged that improvements needed to be made and has since embarked on a process of doing so, it has proposed that $240 million of the expenditure disallowed by the Authority should now be included in its capital base. The Authority's view is that any improvements made by Western Power to its processes since the last access arrangement review will not change the findings of the Authority in relation to past expenditure. Consequently, the Authority does not agree that the $240 million should now be added to Western Power's opening capital base.

Tariff Equalisation Contributions[17]

47. The Authority considers the tariff equalisation contribution (TEC) is not a cost related to the provision of electricity network services to Western Power's customers. However, the Access Code requires that Western Power be able to recover these costs. As Western Power has not yet been required, by a notice made under section 129D(2) of the *Electricity Industry Act 2004* (**Act**), to pay a TEC into the Tariff Equalisation Fund during the third access arrangement period, Western Power has proposed an estimate of the amount. The Authority has estimated the distribution network reference tariffs on the basis of the approved target revenue plus an allowance for the expected TEC amount.

[16] The Authority's detailed reasoning in relation to capital expenditure previously disallowed is set out in paragraphs 448 to 494 of this Draft Decision.

[17] The Authority's detailed reasoning in relation to Tariff Equalisation Contributions is set out in paragraphs 1034 to 1040.

48. The Authority notes that if the tariff equalisation contribution was not included in Western Power's costs, network tariffs would be 5.5 per cent lower than the current levels.

Deferred Revenue[18]

49. The Authority considers the deferred revenue of $967 million should not all be recovered during the third access arrangement and in this draft decision has adopted a recovery period of ten years to avoid price shock to customers for the purpose of this Draft Decision.

Incentives

50. Incentive mechanisms to encourage Western Power to provide services to customers at an efficient cost form an important part of the regulatory regime. The incentive framework contained in this Draft Decision is designed to ensure Western Power provides services at an efficient cost. The incentive framework includes:

- a Gain Sharing Mechanism – a mechanism to provide a reward for any out-performance of operating expenditure forecasts included in this draft decision;
- a Service Standard Adjustment Mechanism – a mechanism designed to reward (or penalise) Western Power for out-performing (under-performing) on its service performance against benchmarks;
- an assessment of the efficient capital expenditure during the second and third access arrangement periods; and
- an assessment of the efficient base operating expenditure during the third access arrangement, and the inclusion of a 2 per cent annual efficiency adjustment in operating expenditure during the third access arrangement period.

[18] The Authority's detailed reasoning in relation to deferred revenue is set out in paragraphs 995 to 1033 of this Draft Decision.

Draft decision and indicative price impacts

51. The draft decision of the Authority is to not approve the proposed access arrangement revisions. The detailed reasons for this draft decision are outlined in the following sections of this document.

52. The Authority's draft decision results in a forecast target revenue of $6.8 billion[19] for the third access arrangement period which is 34 per cent below Western Power's forecast. This target revenue results in annual real tariff reductions of around 0.4 per cent, compared with Western Power's proposed real increases of 16.4 per cent in 2012/13, followed by increases of approximately 11 per cent for the following years.

53. Network charges make up approximately 40 per cent of total electricity costs for residential customers.

54. The main differences between the Authority's draft decision and Western Power's proposal relate to a reduced WACC, a lower allowance for capital and operating expenditure and adjusting the recovery period of revenue deferred from the second access arrangement period from 5 years to 10 years. These differences are summarised in Table 1 below.

Table 1 Comparison of Western Power proposal and Draft Decision

	Western Power Proposal	Draft Decision
Present value of target reference service revenue	$7,899.1 million	$6,133.1 million
Capital Expenditure previously disallowed as inefficient (real)	$244 million	$0
WACC[20]	8.82%	4.73%
Opening Capital Base for AA3 (real)	$7,098.0 million	$6,525.2 million
Forecast Capital Base for AA4 (real)	$10,414.8 million	$9,016.3 million
Capital Expenditure (real)	$5,079.8 million	$4,138.6 million
Operating Expenditure (real)	$2,713.6 million	$2,191.8 million
Present value of deferred revenue recovered	$756.0 million	$413.8 million
Forecast average network tariff increase on 1 July 2012	CPI + 16.4%	CPI - 1.0%
Forecast average network tariff increase on 1 July 2013	CPI + 11.1%	CPI - 0.7%
Forecast average network tariff increase on 1 July 2014	CPI + 11.2%	CPI - 0.4%
Forecast average network tariff increase on 1 July 2015	CPI + 11.4%	CPI - 0.1%
Forecast average network tariff increase on 1 July 2016	CPI + 11.5%	CPI + 0.2%

55. The Authority also requires a number of amendments to be made to the access arrangement including:

---

[19] The forecast target revenue includes $906.9 m relating to the TEC, which is required to be paid by Western Power but does not fall within the Authority's approval process.

[20] Western Power proposed a real pre-tax WACC, whereas the Authority's Draft Decision is on a real post-tax basis. The Authority has determined a real post tax WACC of 3.87%. To be comparable with Western Power's proposed WACC, the pre-tax equivalent of 4.73% has been shown in Table 1.

- revisions to the proposed service standard benchmarks and service standard adjustment mechanism to include a number of existing measures Western Power was proposing to remove and to ensure the proposed benchmarks reflect current levels of service;
- revisions to the proposed revised applications and queuing policy to take account of issues raised by interested parties, particularly in relation to the operation of the competing applications groups.

56. The proposed new charging scheme for distribution low voltage connections has not been considered in this draft decision as an amendment to the Access Code is required before such a scheme could be introduced.

57. Each of the required amendments is discussed in the relevant sections of the draft decision.

58. The amendments that are required to be made to the proposed access arrangement revisions before the Authority will approve it are listed in Appendix 1. For the purposes of clarity, the required amendments are also indicated in the reasons for this Draft Decision at the point at which each relevant element of the proposed revised access arrangement is considered.

59. The Authority invites submissions on this Draft Decision. The closing date for submissions is 1 May 2012. Any submission made by Western Power may include a revised proposed access arrangement.[21]

60. Under section 4.17 of the Access Code, the Authority will consider any submissions received on the Draft Decision and make a final decision to either approve or to not approve the proposed revised access arrangement (or revised proposed access arrangement revisions if submitted by Western Power).

[21] Access Code, Section 4.16.

CONTENT OF AN ACCESS ARRANGEMENT

61. The required content of an access arrangement is specified in Chapter 5 of the Access Code. Section 5.1 of the Access Code requires that an access arrangement:

- specify one or more reference services under section 5.2 of the Access Code;
- include a standard access contract under sections 5.3 to 5.5 of the Access Code for each reference service;
- include service standard benchmarks under section 5.6 of the Access Code for each reference service;
- include price control under Chapter 6 of the Access Code;
- include pricing methods under Chapter 7 of the Access Code;
- include a current price list under Chapter 8 of the Access Code and a description of the pricing years for the access arrangement;
- include an applications and queuing policy under sections 5.7 to 5.11 of the Access Code;
- include a contributions policy under sections 5.12 to 5.17D of the Access Code;
- include a transfer and relocation policy under sections 5.18 to 5.24 of the Access Code;
- if required under section 5.25 of the Access Code, include efficiency and innovation benchmarks under section 5.26 of the Access Code;
- include provisions dealing with supplementary matters under sections 5.27 and 5.28 of the Access Code; and
- include provisions dealing with:
  - the submission of future proposed revisions to the access arrangement under sections 5.29 to 5.33 of the Access Code, including specification of a revisions submission date and target revisions commencement date; and
  - trigger events under sections 5.34 to 5.36 of the Access Code that require the service provider to submit proposed amendments to the access arrangement.

62. The reasons for the Authority's Draft Decision address elements of the revised proposed access arrangement in the following order.

- The "introduction" and "definitions" sections of the access arrangement, which are additional to the elements of an access arrangement required under section 5.1 of the Access Code.
- Reference and non reference services.
- The price control and total costs and target revenue for the provision of covered services and reference services.
- Service standard benchmarks.
- Pricing methods including the actual reference tariffs determined for the first year of the access arrangement period.

- Mechanisms that affect the determination of target revenue in the next access arrangement period including efficiency and benchmarks applying to the provision of covered services.
- Trigger events.
- Standard Access Contract.
- Applications and Queuing Policy.
- Contributions Policy.
- Transfer and Relocation Policy.
- Various supplementary matters in relation to the provision of covered services that are required to be addressed in the access arrangement.

INTRODUCTION TO THE ACCESS ARRANGEMENT

Access Code Requirements

63. The introduction to the current access arrangement includes dates for revision of the access arrangement, for which specific requirements exist under the Access Code. Under sections 5.29 and 5.31 of the Access Code, an access arrangement must specify:

- a revisions submission date that is at least six months before the target revisions commencement date; and
- a target revisions commencement date that must be five years after the start of the access arrangement period, unless a different date is proposed by the service provider and the different date is consistent with the Code objective.

Current Access Arrangement

64. Section 1 of the current access arrangement comprises an introduction that includes the proposed purpose of the access arrangement, start date, revisions submission and commencement dates, and a list of the elements of the access arrangement. A section in this introduction describes the access arrangement's relationship to the Technical Rules and access arrangement information.

65. Section 2 of the current access arrangement relates to interpretation of certain terms used throughout the access arrangement.

66. The current access arrangement specifies a revisions submission date of 1 October 2011 and a target revisions commencement date of 1 July 2012.

Proposed Revisions

67. Proposed revisions to the introduction section of the access arrangement include:

- a definitions and interpretations sub-section similar to Section 2 of the current access arrangement;
- a specified date of commencement of the proposed revisions of 1 July 2012 or a later date as specified by the Authority in accordance with section 4.26 of the Access Code; and
- a proposed revisions submission date of 1 March 2016 and a target revisions commencement date of 1 July 2017, indicating an access arrangement period of five years from 1 July 2012.

Submissions

68. No submissions made to the Authority address matters in either sections 1 or 2 of the proposed access arrangement revisions, including the proposed revisions submissions date or target revisions commencement date.

Considerations of the Authority

69. The Authority notes Western Power has proposed simplifying the wording of section 1.1.2. The Authority agrees the simplification of the description of the network is appropriate but considers some other parts of the existing text which Western Power proposes deleting should be retained for clarity. The text should be revised as set out in Amendment 1 below.

Required Amendment 1

Section 1.1.2 of the proposed revised access arrangement must be amended to include the underlined text as follows:

"This access arrangement <u>sets out the terms and conditions under which Western Power will provide users and applicants with access</u> to the Western Power Network…"

70. Section 1.5.1 of the proposed revised access arrangement includes a listing of the appendices to the access arrangement. Section 1.5.1(e) refers to Appendix C.3, the distribution low voltage connection scheme methodology. Currently the Access Code does not permit such a scheme as it falls above the threshold set for such schemes as set out in section 5.17D(b) of the Code. Until such an amendment is made, the Authority is unable to approve the scheme. Consequently, the reference to Appendix C.3 should be removed and the remainder of section 1.5.1 renumbered accordingly. The proposed inclusion of the distribution low voltage connection scheme methodology is considered in paragraphs 1613 to 1615 of this draft decision.

Required Amendment 2

Section 1.5.1(e) of the proposed revised access arrangement must be deleted and sections 1.5.1 (f) to 1.5.1 (i) renumbered accordingly.

71. The Authority observes that the changes proposed for section 1 of the access arrangement, other than those referred to in paragraphs 69 and 70, are either necessary updates to reflect revisions to the access arrangement for the third access arrangement period, such as stated time periods, or are of an editorial rather than substantive nature.

72. The Authority is satisfied that the general matters addressed in the introduction and definitions of the revised proposed access arrangement are consistent with the Access Code and the Code objective.

73. The Authority has assessed the proposed revisions submission date and revisions commencement date against the specific requirements of section 5.31 of the Access Code.

74. The proposed target revisions commencement date of 1 July 2017 implies an access arrangement period of five years duration from 1 July 2012. This complies with the time period specified in section 5.31(b) of the Access Code.

75. The proposed revisions submission date of 1 March 2016 is fifteen months before the proposed target revisions commencement date of 1 July 2017. This complies with the time period specified in section 5.31(a) of the Access Code which requires the revisions submission date to be at least six months before the target revisions commencement date.

REFERENCE AND NON-REFERENCE SERVICES

Access Code Requirements

76. A reference service is a service described in the access arrangement and for which a reference tariff is specified in the access arrangement. A reference service is a service that would typically be sought by a third party seeking access to the network and is in the nature of a 'benchmark service' for those seeking to negotiate access. Parties are free to negotiate any service with the service provider.

77. Section 5.1(a) of the Access Code requires that an access arrangement specify one or more reference services.

78. The requirements for reference services are set out in section 5.2 of the Access Code:

> 5.2 An access arrangement must:
>
> (a) specify at least one reference service; and
>
> (b) specify a reference service for each covered service that is likely to be sought by either or both of:
>
> (i) a significant number of users and applicants; or
>
> (ii) a substantial proportion of the market for services in the covered network;
>
> and
>
> (c) to the extent reasonably practicable, specify reference services in such a manner that a user or applicant is able to acquire by way of one or more reference services only those elements of a covered service that the user or applicant wishes to acquire; and
>
> (d) for the covered network that is covered under section 3.1 – specify one or more reference services such that there is both:
>
> (i) a reference service which enables a user or applicant to acquire an entry service at a connection point without a need to acquire a corresponding exit service at another connection point; and
>
> (ii) a reference service which enables a user or applicant to acquire an exit service at a connection point without a need to acquire a corresponding entry service at another connection point.

79. The Access Code includes definitions of a number of terms that are relevant to understanding the reference services in the access arrangement.

> "Covered service" means a service provided by means of a covered network, including:
>
> (a) a connection service; or
>
> (b) an entry service or exit service; or
>
> (c) a network use of system service; or
>
> (d) a common service; or
>
> (e) a service ancillary to a service listed in paragraphs (a) to (d) above,
>
> but does not include an excluded service.

"Entry service" means a covered service provided by a service provider at an entry point under which the user may transfer electricity into the network at the entry point.

"Exit service" means a covered service provided by a service provider at an exit point under which the user may transfer electricity out of the network at the exit point.

"Excluded service" means a service provided by means of a covered network, including:

(a) a connection service; or

(b) an entry service or exit service; or

(c) a network use of system service; or

(d) a common service; or

(e) a service ancillary to a service listed in paragraphs (a) to (d) above,

which meets the following criteria:

– the supply of the service is subject to effective competition, and

– the cost of the service is able to be excluded from consideration for price control purposes without departing from the Code objective.

"Reference service" means a covered service designated as a reference service in an access arrangement under section 5.1(a) for which there is a reference tariff, a standard access contract and service standard benchmarks.

"Non-reference service" means a covered service that is not a reference service.

"Reference tariff" means the tariff specified in a price list for a reference service.

80. The designation of any service as an excluded service is subject to determination by the Authority under section 6.33 of the Access Code. Other than as determined by the Authority under this section, all services provided by means of the covered network are covered services.

Current Access Arrangement

81. The current access arrangement at sections 3.4 to 3.6A includes the following 14 reference services:

- Anytime Energy (Residential) Exit Service, A1
- Anytime Energy (Business) Exit Service, A2
- Time of Use Energy (Small) Exit Service, A3
- Time of Use Energy (Large) Exit Service, A4
- High Voltage Metered Demand Exit Service, A5
- Low Voltage Metered Demand Exit Service, A6
- High Voltage Contract Maximum Demand Exit Service, A7
- Low Voltage Contract Maximum Demand Exit Service, A8
- Streetlighting Exit Service, A9

- Un-Metered Supplies Exit Service, A10
- Transmission Exit Service, A11
- Distribution Entry Service, B1
- Transmission Entry Service, B2
- Time of Use (Residential) – Bi-directional Service , C1

82. The current access arrangement at section 3.12 also includes a description of a range of non-reference services that are in the nature of ancillary services.

83. The current access arrangement does not specify any services as excluded services.

Proposed Revisions

84. Western Power has proposed revisions to the eligibility criteria for all reference services and added three new bi-directional reference services to its list of reference services. Western Power has also removed any details in relation to non-reference services from the proposed revised access arrangement.

85. Western Power advises that, as was the case for the second access arrangement period, it does not intend to provide any excluded services during the third access arrangement period.

Eligibility Criteria for Reference Services

86. In its proposed revised access arrangement information, Western Power notes that from time to time it connects large generation or load where an exemption from the Technical Rules has been agreed by the customer, or where a different service level, contract and tariff from the service standard benchmark, electricity transfer access contract and reference tariff respectively have been agreed. Western Power states that, for ease of administration and with the customer's agreement, its current practice is to treat the related service as a reference service. It proposes revising this approach for the third access arrangement period.

87. To achieve this, Western Power has amended the eligibility criteria for all reference services such that consumers are not eligible for a reference service if any of the following apply:

    - The consumer has been granted an exemption from the Technical Rules under section 12.34 of the Code; or
    - Under an agreement with Western Power:
        - The terms and conditions of the access contract under which the service will be provided are materially different to the Applicable Standard Access Contract for this service;
        - The tariff that determines the charge is different to the Applicable Reference Tariff for this service; or
        - The User is to receive delivered electricity at a service standard different to the Applicable Service Standard Benchmarks for this service.

88. In its proposed revised access arrangement information Western Power states that customers will see little practical difference and that the circumstances described are

currently the subject of negotiation between the parties as if the services were non-reference services. Western Power considers the proposed revisions simply make the terminology and concepts used consistent with the requirements of the Access Code. It considers there is no change to a customer's access rights and that, if it does not provide the service sought under a reference or non-reference service, the customer has equivalent rights to seek resolution by way of arbitration. Western Power proposes that tariffs for these services will remain in the revenue cap. This is explained further in paragraphs 177 to179.

New Bi-directional Reference Services

89. Western Power proposes making changes to its bi-directional reference services in response to the rising demand from customers for these services, driven primarily by the increasing number of roof-top photovoltaic (**PV**) systems. Western Power notes that it undertook a review, including consultation with major stakeholders such as the Office of Energy, Synergy and other retailers. The objectives of the review were to:

- address the emerging need for a bi-directional reference service for commercial premises with on-site generation; and
- address implementation issues faced by Synergy that led to the bi-directional reference service introduced in the current access arrangement (to cater for residential premises with small generators) not being taken up.

90. In its current access arrangement, Western Power has a bi-directional reference service for residential distribution users with bi-directional energy flows due to small scale generation, being the "Reference Service C1 - Time of Use (Residential) - Bidirectional Service". This reference service was approved by the Authority as part of Western Power's second access arrangement, however, due to concerns raised by stakeholders, this service has not been implemented. The issues which resulted in the service not being implemented included:

- the need to alter existing metering arrangements as the tariff was based on interval metering data for off-peak, shoulder and on-peak time periods;
- the extent of the additional implementation and transaction costs, particularly in relation to changes to the billing system and metering arrangements, and who should pay for these costs;
- the need for a bi-directional reference service for commercial customers; and
- tariff design issues.

91. The issues relating to pricing methods are discussed in paragraphs 1212 to 1225 of this draft decision.

92. Western Power commissioned Ernst and Young to review the existing reference service and reference tariff for residential distribution users with bi-directional energy flows due to small scale generation and to define a new reference service and reference tariff for commercial distribution users with bi-directional energy flows due to small scale generation for inclusion in the third access arrangement period.

93. Based on the results of the review, Western Power has proposed three new bi-directional reference services, and relabelled the existing "Time of use (residential) bi-directional service, C1" as "C3". The proposed three new bi-directional reference services are:

- Anytime energy (residential) bi-directional service, C1

- Anytime energy (business) bi-directional service, C2
- Time of use (business) bi-directional service, C4

94. The proposed time of use bi-direction services only include two time periods, on-peak and off-peak, which is consistent with the existing exit reference services (A3 and A4).

95. The proposed bi-directional reference services extend to battery storage systems and electric vehicles.

96. The proposed residential bi-directional reference services both include premises occupied by a voluntary/charitable organisation. The current C1 reference service only applies to residential premises.

97. For the proposed C1 residential anytime energy service, users are required to have an accumulation meter having capability for import and export channels. For the proposed C3 residential time of use energy reference service users are required to have either a SmartPower meter or multiple register TOU accumulation meter having capability for import and export channels.

98. For both the proposed business bi-directional services (C2 and C4), the meter can be either an accumulation meter having capability for import and export channels or an interval meter having capability for import and export channels.

Non-reference Services

99. Western Power's access arrangement information notes that it will continue to provide a range of non-reference services during the third access arrangement in response to customer requirements for:

    - Network access services that are not reference services.
    - Miscellaneous services that are ancillary to the conveyance of electricity by means of the Western Power Network (for example the lifting of electrical wires to allow high loads to pass down highways).

100. The Authority notes that if a significant number of users seek a particular network access service not currently offered as a reference service then, under section 5.2(b) of the Access Code, consideration would need to be given at the next access arrangement review for such services to be included as reference services.

101. The table of non-reference services provided in the current access arrangement has not been replicated in the proposed revised access arrangement and all references in the proposed revised access arrangement to charges, terms and conditions for non-reference services have been deleted.

Submissions

Eligibility Criteria for Reference Services

102. In its submission to the public consultation, Synergy states that Western Power's proposed amendment to the eligibility criteria for all reference services has the effect of giving Western Power a discretionary ability to refuse access to reference services. Synergy submits this is not warranted and is contrary to the Access Code objectives

and section 5.2(b) and (c) of the Access Code. The points raised by Synergy are considered in paragraphs 118 to 125 below.

New Bi-Directional Reference Services

103. In its submission, Synergy supports the bi-directional service and tariff structure and states it was happy with the level of review and consultation conducted by Western Power. Synergy states that it indicated to Western Power in April 2011 that it would require six to eight months to make system changes to implement the four new reference services on its system. However, Synergy considers the recent introduction of the federal government's clean energy initiative will impact on its system development resources and that it will now require ten to twelve months to make system changes to implement the proposed bi-directional reference services. In its submission Synergy requests the Authority and Western Power to give regard to this implementation requirement when determining the date these new bi-directional services will take effect.

104. Landfill Gas and Power and Alinta both support the proposed new bi-directional services.

Battery and electrical vehicle systems

105. In its submission, although Synergy supports the proposed revisions to the bi-directional reference services, it does not support these services being extended to the connection of battery and electrical vehicle systems. Synergy notes that, while consultation on bi-directional services generally was good, Synergy was not consulted on the impact of including battery and electric vehicle systems on these bi-directional services. Synergy notes it has already advised Western Power of its concerns and the outstanding matters that need to be addressed before battery and electrical vehicle systems are included in these services.

106. Synergy submits that the various connection configurations and their impacts for battery and electric vehicle systems have not been fully understood and could potentially have adverse impacts on retailers and government policy, especially in circumstances where retailers do not have knowledge of where these systems are located. This puts retailers in a position where they are in breach of clause 3 of the standard access contract, because retailers do not have the necessary information to ensure the correct retail contract, reference service and metering arrangements have been put in place.

107. Synergy submits that, in light of the connection issues experienced with photovoltaic systems, there needs to be further work done to understand Western Power's process of how such battery and electric vehicle systems connect to the network and are permitted by Western Power to operate simultaneously with other systems such as photovoltaic systems, including what this means in terms of system peak and increasing the cost of network augmentations.

108. Synergy considers further work is needed to understand the customer, commercial and contractual impacts of connecting and operating battery and electric vehicle systems (especially if these systems are operating simultaneously with photovoltaic systems). Synergy envisages that without further work in this area being undertaken to fully understand the issues, customers could be adversely impacted. Synergy believes a number of customers, contrary to the Applications and Queuing Policy, have breached their supply contracts by getting Western Power's approval to connect,

energise and operate bi-directional equipment on the network. Synergy states these arrangements are often implemented between the customer and Western Power without Synergy's knowledge and also cause Synergy to breach its access contract with Western Power.

109. Synergy considers the photovoltaic connection process has highlighted shortcomings in Western Power's connection and notification procedures. Synergy considers a key reason for this is because there is no independent mechanism or audit process that ensures Western Power complies with its Access Arrangement. Synergy considers further work needs to be done on the cost of connections and how Western Power will approve, connect and energise battery and electric vehicle systems, including what type of connection configuration it will permit and how it will notify the retailer.

110. In addition, Synergy notes it will require clarity from the Office of Energy on whether a customer will be entitled to a feed-in-tariff payment for electricity exported into the network, as recorded on Western Power's meter, from a battery. Synergy considers it is not clear how Western Power will track the location of these systems, how meters will differentiate electricity that is exported from a photovoltaic system and electricity that is exported from a battery or how Synergy will receive this information under the Metering Code Communications Rules.

111. Synergy's submission highlights that it has not requested a bi-directional service for battery and electrical vehicle systems. Synergy notes its request for a bi-directional service in the second access arrangement was intended to meet the requirements of Synergy, its customers and state government policy for photovoltaic systems. Synergy's requirement for a bi-directional service in this regard has not changed and that the key reason why the previous bi-directional service was not implemented was because it operated contrary to state government policy and Synergy's ability to meet those objectives.

112. Synergy notes that section 5.2(c) of the Code requires an access arrangement to allow a user to acquire by way of one or more reference services only those elements of a covered service that the user wishes to acquire. On the basis that it is the exclusive service provider to the residential market in the SWIS, Synergy submits the Authority must, in the absence of any other compelling evidence of significant need, give regard to Synergy's concerns associated with battery and electric vehicle systems and the connection issues associated with photovoltaic systems and exclude battery and electric vehicle systems from the proposed revised bi-directional services.

113. Synergy notes it will make a separate request for a reference service to cover battery and electric vehicle systems once the policy, commercial, connection process and technical requirements have been clarified and there is significant demand from customers to connect battery and electric vehicle systems.

Connection Service Reference Service

114. In its submission Verve Energy notes that it has unsuccessfully argued at previous access arrangements reviews for the incorporation of a Connection Access Contract as a reference service. Verve Energy continues to consider such a service should be available.

Constrained Network Connections

115. In its submission ERM Power considers that a major reference service item overlooked in the third access arrangement period information is a proposal for charging arrangements for constrained network connections. ERM notes that moving away from a model of unconstrained network connection offers to constrained connections was a key part of Western Power's submission to the Office of Energy's Strategic Energy Initiative. ERM views this as an essential part of increasing the efficient utilisation of the network assets and believes provision for these services needs to be addressed so that the services are available as soon as possible during the third access arrangement period.

Considerations of the Authority

116. Set out below are the Authority's considerations of the following matters relating either to proposed revisions to the access arrangement or matters raised in submissions.

- The information provided in support of the specification of reference services.
- Changes to the eligibility criteria for all reference services.
- Additional bi-directional reference services.
- Constrained network connections.
- Inclusion in the access arrangement of a connection access contract as a reference service.

Information in Support of Reference Services

117. Western Power has not provided information in support of the specification of reference services and compliance with the requirements of section 5.2 of the Access Code. However, the Authority considers that this supporting information is not required, given that the access arrangement has been in operation for over five years and users (and prospective users) of the network have the opportunity during the access arrangement review process to provide information as to whether the reference services specified in the access arrangement meet their requirements.

Eligibility Criteria for Reference Services

118. The Authority notes that the only practical significance of Western Power's proposal to amend the eligibility criteria for reference services is that it clarifies the operation of the access disputes mechanism of Chapter 10 of the Access Code in the event that there is an access dispute over the terms or the tariff for a service. By classifying services provided with different terms, tariffs or service standards from a reference service as a non-reference service, an arbitrator would clearly not be bound to determine that the service must be provided at the reference tariff (section 10.20 of the Access Code) or provided on terms as set out in a standard access contract for a reference service (sections 10.21 and 10.22).

119. As Western Power has proposed that these non-reference services will remain subject to the revenue-cap price control, the designation of these services as a non-reference service will not alter the operation of the price control of the access arrangement.

120. The Authority has considered the issues raised by Synergy but does not consider they provide reason to reject Western Power's proposed approach. Each of the issues raised by Synergy is addressed below.

121. The proposed amendments do not affect the ability of a user to obtain a reference service in accordance with the Technical Rules, the terms of the standard access contract and the reference tariff. This ability is ultimately enforceable by resort to arbitration on an access dispute. Accordingly, the Authority does not agree with Synergy's assertion that the proposed amendments to the eligibility criteria for all reference services has the effect of giving Western Power a discretionary ability to refuse access to reference services.

122. Synergy considers the proposed amendments to the eligibility criteria are contrary to the requirements of section 5.2(c) of the Access Code in that they prevent a user from obtaining only those elements of a covered service that the user is seeking. However, the Authority notes that section 5.2(c) of the Access Code requires only that reference services be specified in such a way that a user can acquire one or more reference services to obtain only those elements of a covered service that the user wishes to acquire.

123. Synergy considers the proposed eligibility criteria blurs the line between a reference service that must be provided to users and the contractual requirements for use of a service. Synergy considers a user's right to a reference service should not be conditional or linked to matters such as whether the terms of an access contract are materially different to a standard access contract or an exemption from the Technical Rules or a different service standard.

124. However, the Authority considers that a negotiated material change to the terms of a reference service (which would include a substantive departure from the technical rules requiring an exemption, or a different service standard) must result in that service no longer being treated as a reference service for the purposes of the Access Code. This is because the definition of a reference service in the Access Code expressly defines a reference service by reference to it being designated as a reference service in an access arrangement under section 5.1(a) "for which there is a reference tariff, a standard access contract and service standard benchmarks". The link between a reference service and its terms and conditions is also supported by section 10.21 of the Access Code which prevents the arbitrator from determining terms for a reference service that are inconsistent with the standard access contract for the reference service.

125. Synergy considers eligibility criteria for reference services that contemplate a change to the terms of the service that cause the service to no longer be a reference service are contrary to a requirement of the Access Code that reference services should be "what the users want". The Authority rejects this argument on the basis that the issue whether users may negotiate different terms from those of a reference service is an entirely different matter from the question whether the reference service (as defined in the access arrangement and by the standard access contract) meets the requirements of section 5.2(b) of the Access Code.

Additional Bi-directional Reference Services

126. Under clause 5.2(b)(i) of the Access Code, Western Power is required to specify a reference service for each covered service that is likely to be sought by a significant number of users and applicants.

127. The Authority considers that the number of connection points for which a business bi-directional service is required by Synergy (and potentially other users) means that the service is likely to be sought by a significant number of users. Accordingly, the Authority agrees that the proposed access arrangement revisions should make provision for a reference service for a business bi-directional connection point and that both the anytime energy and time of use reference service should apply to premises occupied by voluntary/charitable organisations as proposed by Western Power as this is consistent with existing residential reference services (A1 and A3).

Battery and Electrical Vehicle Systems

128. As outlined above, Synergy has identified a number of issues in relation to the provision of services to battery storage and electrical vehicle systems. The Authority agrees that further work is needed to understand and resolve these issues. Given the issues which arose resulting in the non-implementation of the C1 reference service during the current access arrangement period, the Authority agrees these issues should be resolved before extending the new bi-directional reference services to battery and electrical vehicle systems. The Authority notes that such services can still be provided as non-reference services.

Required Amendment 3

The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems unless the issues identified in paragraphs 105 to 113 above are resolved.

Size of Inverter

129. The Authority notes the threshold for inverter size for the proposed revised residential bi-directional tariffs is consistent with the current residential bi-directional tariff.

130. The Authority notes the threshold for the proposed business bi-directional tariffs of 1 MVA is consistent with the Access Code requirement for the use of average, non-locational tariffs for all connections below 1 MVA. Western Power has advised that the threshold of 1 MVA will allow the reference service to cover the greater portion of the market for bi-directional services and that installations above 1 MVA would be charged on the basis of the existing entry and exit reference services for distribution customers (A8 and B1).

Metering requirements for Bi-directional Reference Services

131. The Authority notes that the metering provisions proposed by Western Power are designed to ensure existing customers with small scale generation who have already had an upgraded two channel, five register interval meter installed at the connection point will not need their current meter arrangement altered in any way. This matter was covered by the consultation exercise carried out by Ernst and Young on behalf of Western Power, and no further comments have been made in submissions during the public consultation.

Voluntary/Charitable Organisations

132. The Authority notes that extending the proposed revised residential bi-directional tariffs to voluntary/charitable organisations is consistent with the existing residential exit services, A1 and A3.

Non-reference Services

133. The Authority notes that Western Power's proposed revisions delete any description of non-reference services from the access arrangement.

134. The Access Code does not include a requirement for an access arrangement to include a list of non-reference services. These services can be included in the access arrangement at Western Power's discretion. Regardless of whether a list of non-reference services is included or not, it does not limit the range of non-reference services that Western Power may provide, nor that a prospective user may request.

Connection Service Reference Service

135. As was the case at the time of the current access arrangement review, Verve Energy has submitted that the access arrangement should include a connection service, preferably as a reference service or otherwise as a non-reference service on specified terms and conditions. This matter has been previously considered by the Authority and its view, which has not changed, is set out below.

136. Western Power had, in its originally proposed access arrangement in 2005, specified a connection service as a non-reference service and included in the proposed access arrangement a standard access contract (the "connection access contract") for the connection service. The connection access contract comprised terms and conditions for a contract between Western Power and an electricity customer (who is usually the controller of a connection point). The connection access contract was intended to apply in the circumstances referred to by Verve Energy's current submission; that is, where the user of network services and the controller of the connection point are different persons. The connection access contract proposed by Western Power consisted of all the terms and conditions of the electricity transfer access contract except for those directly dealing with electricity transfer. Western Power stated the following reasons for including the connection access contract in the access arrangement as a standard access contract:

- The access contract should deal with the reference services defined in the access arrangement, being exit and entry services.
- The party receiving connection services (a non-reference service) may not be the contracted recipient of exit or entry services.
- The original contracting party to the construction of connection assets for which a contribution was required may not be a party to a contract for reference services.

137. The inclusion in the access arrangement of a connection service and an associated standard contract was addressed by the Authority in its consideration and approval of the proposed access arrangement in 2007. In its Final Decision, the Authority observed that the reference tariffs indicated in Western Power's proposed price list included charges in respect of connection assets for three reference services: the Distribution Entry Service (B1), the Transmission Entry Service (B2) and the Transmission Exit Service (A11). The Authority concluded that the inclusion of

connection charges in the reference tariffs for these services indicated that connection services are part of these reference services. The Authority further reasoned that, as it is not physically possible to utilise any of these reference services without the connection assets and services, it is appropriate for the relevant entry and exit services to be bundled with connection services in this manner. Taking these matters into account, the Authority considered that it was not necessary for connection services to be defined as separate reference services.

138. The Access Code does not require a service provider to include in an access arrangement a designation or description of non-reference services or a standard access contract for non-reference services. Under section 4.29(c), the Authority cannot require a service provider to include these matters in an access arrangement.

139. The relevant matter for the Authority to consider in response to the submission from Verve Energy is therefore whether the access arrangement should include a connection service as a reference service together with, necessarily, a reference tariff, a standard access contract and service standard benchmarks.

140. A connection service is defined in section 1.3 of the Access Code as "a right to connect facilities and equipment at a connection point". A note to this definition indicates that "a connection service is the right to physically connect to the network and will regulate technical compliance etc. It is not the same thing as an entry or exit service, which embody rights to transfer electricity."

141. Applying this definition, the Authority understands that the provision by Western Power of a connection service would involve executing a contract for the connection service; specifying relevant technical requirements for the connection service; provision, maintenance and operation of relevant connection assets; and monitoring of compliance with contractual and technical requirements. It is further understood that a connection service would typically be sought or provided separately from an entry or exit service for generators and for consumers of large amounts of electricity whose operations have the potential to disrupt the network. Where a price is charged for a connection service separately from a price charged for the electricity transfer service, that price would typically be specific to the party receiving the service, reflecting the cost of user-specific assets utilised for provision of the connection service.

142. Under clause 6.1(e) of the standard access contract for reference services (the "electricity transfer access contract") under both the current access arrangement and proposed access arrangement revisions, Western Power may require the user to procure that a controller of a connection point enter into a connection contract with Western Power in respect of a connection point. Under the definition of a connection contract in the electricity transfer access contract, the connection contract may encompass the terms of the electricity transfer access contract, other than the terms (clauses 3 to 9) that deal with the transfer of electricity, or comprise of an agreement with materially equivalent terms and conditions.

143. The Authority observes that in the National Electricity Market (**NEM**) (and under the National Electricity Rules) connection services are treated as negotiated services, meaning that the price and terms for the connection services are subject to determination by negotiation (in accordance with negotiation principles), with resolution of disputes by arbitration.

144. The Authority considers that it is not practical to include a connection service as a reference service under the access arrangement. As the cost of providing the

connection service, and hence the relevant price for the service, would typically be specific to the party receiving the service, the Authority does not consider that it would be practical to establish a reference tariff for a connection service. The only manner in which a reference tariff could be ascribed to a connection service would be to determine a separate reference tariff for each party to whom the service is provided, which would be inconsistent with the concept of a reference service. In the absence of a reference tariff for an individual connection service, it is not possible to include a connection service in the access arrangement as a reference service, or to require that the access arrangement include a standard access contract for a connection service.

Constrained Network Connection

145. The Authority notes that users are able to obtain constrained access as a non-reference service where this can be accommodated by network operating conditions. If constrained access were to be offered as a reference service, then Western Power would be required to provide the service regardless of the impact on the network. The Authority notes that consideration is being given to the merits of moving to a constrained network approach; however, this falls outside the scope of the access arrangement review process.

TOTAL REVENUE REQUIREMENT

Introduction

146. In this section of the Draft Decision, the Authority addresses the determination of target revenue for the third access arrangement period and the form of the price control.

147. Western Power has determined a value of target revenue by reference to forecast costs for the third access arrangement period – the “building block” method. This is consistent with section 6.2(a) of the Access Code and with the method for determination of target revenue for the first and second access arrangement periods.

148. The Authority’s assessment of Western Power’s determination of target revenue is documented in the following sections of this Draft Decision, addressing the following matters:

- form of price control;
- forecasts of demand for services;
- forecast operating expenditure;
- amounts of actual and forecast capital expenditure and values of the regulated capital base at the commencement of the second access arrangement period and a notional regulated capital base over the term of the third access arrangement period;
- a return on the regulated capital base;
- taxation on capital contributions;
- an allowance for working capital;
- an amount of tariff equalisation contributions; and
- adjustments to target revenue for the third access arrangement period to reflect certain cost and revenue outcomes for the second access arrangement period.

149. In considering Western Power’s proposed target revenue, the Authority has made assessments of the actual and forecast costs of Western Power over the second and third access arrangement periods, including:

- an assessment of whether the forecast operating costs for the third access arrangement period meets the requirement of section 6.40 of the Access Code of including only those costs that would be incurred by a service provider efficiently minimising costs;
- an assessment of whether capital expenditure in the second access arrangement period may be added to the capital base of the network under the provisions of section 6.51A of the Access Code, including an assessment of whether, and to what extent, the capital expenditure satisfies the new facilities investment test (**NFIT**) under section 6.52 of the Access Code; and
- an assessment of whether forecast capital expenditure for the third access arrangement period may be taken into account in determining target revenue (by notional addition to the regulated capital base), including an assessment of whether, and to what extent, the capital expenditure satisfies the new facilities investment test under section 6.52 of the Access Code.

150. For the purposes of the approval of proposed access arrangement revisions, and pursuant to sections 6.41, 6.51 and 6.51A of the Access Code, the Authority has discretion whether to recognise costs in the total costs and target revenue that underlie the price control. This includes forecast operating costs, actual capital expenditure during the second access arrangement period and forecast capital expenditure for the third access arrangement period. Before recognising these costs in total costs and target revenue, the Authority must be satisfied that the costs meet the tests of section 6.41, 6.51 and 6.51A of the Access Code. The responsibility rests with Western Power to demonstrate to the Authority that the costs satisfy these tests.

151. In making an assessment of costs, the Authority has obtained advice from Geoff Brown & Associates on a range of relevant matters including:

- a review of Western Power's forecast expenditures for the third access arrangement period;
- a review of Western Power's governance arrangements as they relate to the control of work programs and costs; and
- a review of a sample of capital projects and programs and the amounts of new facilities investment for these projects and programs claimed by Western Power to meet the new facilities investment test under section 6.52 of the Access Code.

152. In making an assessment of costs, the Authority had regard to:

- Western Power's performance during the first and second access arrangements:
  - significant under expenditure during the second access arrangement period compared with the forecast costs approved by the Authority in its final decision in relation to the second access arrangement period;
  - good service standard performance during the second access arrangement period; and
  - notwithstanding the improvements that have been made during the second access arrangement period, the ongoing deficiencies in relation to Western Power's management and governance processes for undertaking operating and capital activities.
- Significant increases in Western Power's expenditure forecast for the third access arrangement period compared with actual expenditure during the second access arrangement period.
- Western Power's management of its wood poles:
  - an outstanding Energy Safety Order in relation to the condition of Western Power's wood poles;
  - the 2011 Asset System Review[22], which identified issues with Western Power's asset information; and
  - a recent Parliamentary inquiry into Western Power's management of wood poles which has highlighted serious weaknesses in Western Power's asset management procedures including its management of asset data.

[22] GHD Asset Management System Review Final Report, October 2011.

- Efficiency of operating expenditure:
  - a comparison of Western Power's costs with other network service providers.
- Proposed methodological changes by Western Power compared with previous access arrangements all resulting in an increase to forecast target revenue.

153. The Authority has assessed the actual and forecast costs against the relevant requirements of the Access Code and, where it is determined that the requirements of the Access Code are not met, exercised discretion to amend the amounts of costs to be taken into account in determination of target revenue.

Form of Price Control

Access Code Requirements

154. Section 5.1(d) of the Access Code requires that an access arrangement include a price control. "Price control" is defined in the Access Code as meaning the provisions in an access arrangement, under section 5.1(d) and Chapter 6 of the Access Code, which determine target revenue. A note to this definition indicates that price control can consist of direct or indirect limits, and consists of a limit on the level of tariffs through the control of overall revenue. This note also distinguishes between price control and pricing methods by indicating that pricing methods deal with the structure of tariffs.

155. Sections 6.1 to 6.3 of the Access Code establish requirements for the form of the price control:

> 6.1 Subject to section 6.3, an access arrangement may contain any form of price control provided it meets the objectives set out in section 6.4 and otherwise complies with this Chapter 6.
>
> 6.2 Without limiting the forms of price control that may be adopted, price control may set target revenue:
>
> (a) by reference to the service provider's approved total costs; or
>
> (b) by setting tariffs with reference to:
>
> (i) tariffs in previous access arrangement periods; and
>
> (ii) changes to costs and productivity growth in the electricity industry;
>
> or
>
> (c) using a combination of the methods described in sections 6.2(a) and 6.2(b).

156. Section 6.3 of the Access Code constrains the choice of price control for the first access arrangement period, which is not relevant to the proposed access arrangement revisions.

157. Section 6.4(a) of the Access Code sets out objectives for the price control in relation to the setting of an amount of target revenue for the access arrangement period:

> giving the service provider and opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:

(i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;

plus

(ii) for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;

plus

(iii) an amount (if any) determined under section 6.6;

plus

(iv) an amount (if any) determined under section 6.9;

plus

(v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);

plus

(vi) an amount (if any) determined under section 6.37A.

158. Sections 6.4(b) and 6.4(c) set out further objectives for the price control of:

- enabling a user to predict the likely annual changes in target revenue during the access arrangement period (section 6.4(b)); and
- avoiding price shocks (that is, sudden material tariff adjustments between succeeding years (section 6.4(c)).

Current Access Arrangement

159. The current access arrangement applies a “revenue cap” form of price control. Under this form of price control, reference tariffs are set in any year on the basis of an amount of required revenue for that year, plus corrections for under-recovery or over-recovery of required revenue in prior periods. A separate revenue cap was applied to each of the transmission and distribution networks.

160. The price control also includes provision for adjustments to revenues from one access arrangement period to the next, including provision for adjustments for unforeseen events and technical rule changes, and adjustments under the investment adjustment mechanism and capital contributions adjustment mechanism.

161. The price control includes a separate factor for any costs incurred by the distribution system as a result of any tariff equalisation contribution Western Power is required to pay in accordance with section 6.37A of the Code.

162. The price control under the current access arrangement is applied subject to a "side constraint" on year-to-year changes to reference tariff charges. Under the current access arrangement, the side constraint comprised a factor of +/- (CPI + 13 per cent) for the transmission network and +/- (CPI + 18 per cent) for the distribution network.[23]

Proposed Revisions

163. Western Power has introduced new terms in its proposed revised access arrangement for 'revenue cap services', 'non-revenue cap services' and 'bi-directional services'.

- 'revenue cap services' – means the following covered services provided by Western Power by means of the Western Power Network:
  a) connection service;
  b) exit service;
  c) entry service;
  d) bi-directional service;
  e) the metering services provided ancillary to the services in paragraphs (a) to (d) that are defined as standard metering services in the most recent Model Service Level Agreement approved by the Authority under the *Electricity Industry Metering Code 2005*; and
  f) streetlight maintenance.
- 'non-revenue cap services' – means non-reference services provided by Western Power by means of the Western Power Network other than non-reference services that are provided as revenue cap services.
- 'bi-directional service' – means a covered service provided by Western Power at a connection point under which the user may transfer electricity into and out of the Western Power Network at the connection point.

164. Western Power has proposed that, in accordance with sections 6.1 and 6.2 (c) of the Access Code:

- a revenue cap will apply to revenue cap services that is set by reference to Western Power's approved total costs; and
- charges for non-revenue cap services will be:
  – negotiated in good faith;
  – consistent with the Access Code objective; and
  – reasonable.

165. Western Power has proposed a new method of calculating the side-constraints for the transmission and distribution network which will vary annually based on CPI, percentage change in revenue requirements, correction factors (including an adjustment for under and over-recovery of revenue, adjustments to revenue from the current access arrangement and the TEC) and an additional 2 per cent. The formula

[23] While expressed in this form, the side constraint is a maximum change in any tariff component by a factor of plus or minus the sum of the percentage change in the CPI and 13 percentage points for transmission tariffs and CPI and 18 percentage points for distribution tariffs.

for calculating these side constraints is contained in Western Power's proposed revised access arrangement.[24]

166. For the purposes of calculating the maximum target revenue each year when setting annual tariffs, Western Power has proposed a number of changes:

- the published CPI data relating to the most recent December quarter compared to the December quarter in the previous year will be used rather than the March quarter which is the requirement in the existing access arrangement;
- the formula for calculating the maximum target revenue has been amended to reflect that the annual tariff-setting process for each financial year typically takes place before the end of the previous financial year so the difference in actual revenue compared to the target revenue must be estimated and then recalculated in the subsequent financial year. In the current access arrangement period this was noted in the text of the access arrangement but not explicitly included in the formula; and
- the requirements for calculating the maximum revenue cap have been changed from "will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap" to "will use its reasonable endeavours to ensure that the actual … revenue … is within a reasonable margin of [the maximum revenue cap]".

Submissions

167. In its submission Verve Energy has queried the proposed amendments to the side constraints and considers the proposed methodology could result in uncertain and variable values and unexpected and/or unwarranted outcomes.

168. Landfill Gas and Power notes in its submission that it has calculated Western Power's proposed revised side constraint would result in a weighted average distribution/transmission side constraint of 15.4 per cent for the third access arrangement period which it considers is excessive given the level of tariff increases already embedded in the third access arrangement period proposal of 16.4 per cent in year one followed by 11 per cent in years two to five.

Considerations of the Authority

Form of Price Control

169. Under sections 6.1 and 6.2 of the Access Code, the form of price control is a matter for determination by the service provider subject to the selected form of price control complying with the requirements of section 6.2, the objectives of section 6.4, and otherwise complying with Chapter 6. In considering a proposed form of price control for the purposes of a decision to approve or not approve the proposed access arrangement revisions, the Authority must also have regard to the Access Code objective, which requires that the price control promote the economically efficient investment in and operation and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.

[24] Proposed revised access arrangement, pp. 31-34.

170. A revenue cap is explicitly contemplated in the note to section 6.2(a) of the Access Code as one of several forms of price control that may be adopted.

171. A revenue cap form of price control creates an incentive for a service provider to out-perform the forecast of costs on which the price control was established, or at least to minimise any under-performance relative to that forecast. This incentive arises from the service provider bearing the risk of under-performance relative to cost forecasts, but also retaining the benefits of out-performance of forecasts.

172. A possible consequence of this is that the service provider may be incentivised to defer operating cost expenditure in order to increase out-performance. This is at least partially counteracted by the Service Standard Adjustment Mechanism which financially penalises the service provider for any underperformance on service standards.

173. There is also an incentive for service providers to overstate forecast operating costs in order to increase the opportunities for outperformance. The Authority needs to satisfy itself that the base operating cost expenditure used to prepare the forecasts reflects efficient expenditure and that any increases to the base costs are adequately justified by the service provider.

174. The Authority notes that a revenue cap form of price control does not provide incentives for the service provider to seek to increase demand for services and thereby increase revenue. The absence of incentives under the price control could, all other things being equal, create incentives for a service provider to fail to provide timely services at new connection points. The absence of incentives under the price control is, however, countered by other mechanisms to ensure provision of services. For Western Power, these include requirements under the *Code of Conduct for the Supply of Electricity to Small Use Customers 2004*, the Customer Service Charter, and requirements of the applications and queuing policy of the access arrangement.

175. The Authority also accepts that the revenue cap form of price control could create incentives for Western Power to increase the amount of revenue that it seeks to obtain through contributions. With the treatment of contributions under the proposed access arrangement revisions, revenue obtained from contributions does not fall under the revenue cap. As such, any revenue collected by Western Power from contributions over and above forecasts is retained. However, the Authority considers that Western Power is adequately constrained in its ability to charge contributions by the contributions policy of the access arrangement that limits the circumstances in which contributions may be charged.

176. Taking into account the matters addressed above, the Authority is satisfied that the proposed revenue cap form of price control is consistent with the requirements of the Access Code.

Revenue from Non-Reference Services

177. Under the terms of the current access arrangement the amount of target revenue established under the price control is an amount in respect of reference services only. The derivation of target revenue involves subtraction from total costs of an amount of forecast operating costs attributed to the provision of non-reference services. Under this specification of target revenue and the price control, revenue earned by Western Power from the provision of non-reference services does not fall under the revenue cap price control.

178. As set out in paragraphs 86 to 88 above, for the third access arrangement Western Power has proposed revisions to the eligibility criteria which may result in some network access services currently treated as reference services being classified as non-reference services. However, Western Power has proposed that the revenue cap will apply to all network access services that Western Power provides to transmit and distribute electricity, whether they are a reference or non-reference service.

179. The Authority observes that the designation as a non-reference service of a service with different terms, tariff or service standards from a reference service does not alter the operation of the price control of the access arrangement. The Authority accepts Western Power's proposal for the reason that it is consistent with the distinction between reference and non-reference services in the Access Code and that it is of limited practical consequence. Therefore, the Authority accepts Western Power's proposal to include non-reference service revenue for network access services under the revenue cap.

180. The Authority notes that Western Power has proposed to treat services that are ancillary to the transmission and distribution of electricity, such as high load escorts, as falling outside the of the revenue cap. This is consistent with the methodology approved by the Authority for the second access arrangement period. As this revenue falls outside the revenue cap, the forecast operating costs attributed to such services is deducted from target revenue.

Side Constraint and Calculation of Maximum Target Revenue

181. The Authority considers the operation of the side constraint and the calculation of maximum target revenue are best considered together with pricing methods, price lists and price list information. The Authority's considerations of this are set out in paragraphs 1202 to 1211.

Target Revenue

Access Code Requirements

182. Under section 6.2 of the Access Code, the target revenue for a price control may be set by reference to the service provider's approved total costs; or by reference to tariffs in previous access arrangement periods and changes to costs and productivity growth in the electricity industry; or using a combination of these two methods.

183. Objectives to be observed in setting the level of target revenue are set out in sections 6.4(a) and 6.5 of the Access Code.

> 6.4 The price control in an access arrangement must have the objectives of:
>
> (a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> (i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;
>
> plus:
>
> (ii) for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;
>
> plus:
>
> (iii) an amount (if any) determined under section 6.6 [adjustments for unforeseen events];
>
> plus:
>
> (iv) an amount (if any) determined under section 6.9 [adjustments for technical rule changes];
>
> plus:
>
> (v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);
>
> plus:
>
> (vi) an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32);
>
> plus:–
>
> (vii) an amount (if any) determined under section 6.37A [tariff equalisation contributions];
>
> …

6.5 The amount determined in seeking to achieve the objective specified in section 6.4(a)(i) is a target, not a ceiling or a floor.

Current Access Arrangement

184. Consistent with the requirements of the Access Code, during the first two access arrangement periods, Western Power has determined a level of target revenue using a 'building-block' approach. Total revenue is comprised of:

- operating costs (non-capital costs);
- depreciation;
- return on the regulated capital base; and
- TEC[25].

185. The regulated capital base is derived as follows:

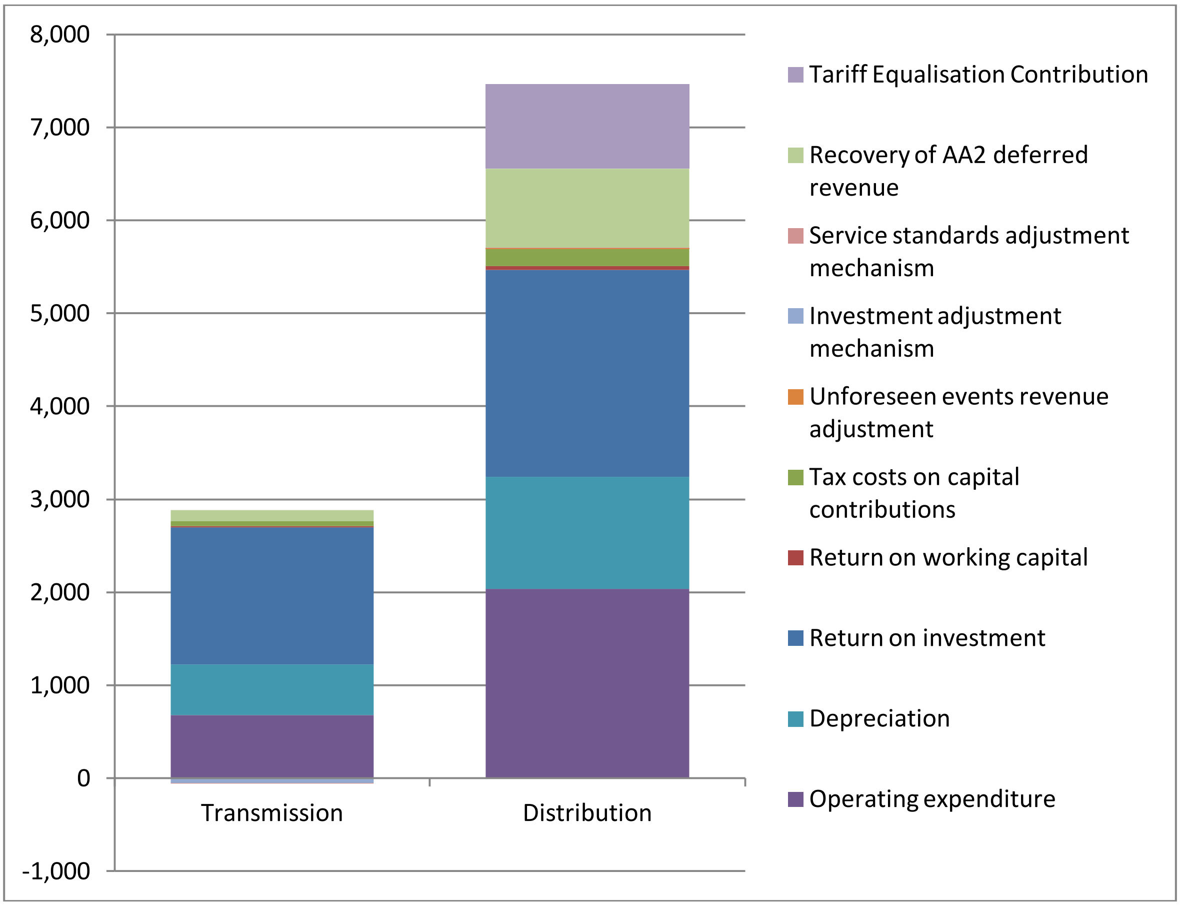
    opening capital base + forecast capital expenditure – depreciation – redundant assets = closing capital base

Proposed Target Revenue

186. Western Power has proposed values of target revenue for the transmission and distribution networks over the third access arrangement period as indicated in Figure 1.

[25] The tariff equalisation contribution is an amount that Western Power is required to pay the Western Australian Government to help finance a subsidy provided to Horizon Power customers.

Figure 1 Western Power proposed transmission and distribution network target revenue (real $ million, dollar values at 30 June 2012)



187. Western Power's proposed 'building block' components of the target revenue for both the transmission and distribution network includes a number of items not included in target revenue for the second access arrangement period:

- recovery of deferred revenue from the current access arrangement;
- adding return on capital expenditure deemed to be incurred mid-year;
- provision for equity raising costs if circumstances arise; and
- recovery of tax on capital contributions.

188. A breakdown of the proposed transmission and distribution network target revenue for each year of third access arrangement period is set out in Table 2 and Table 3 below.

Table 2 Western Power proposed transmission network target revenue (real $ million, at 30 June 2012)[26]

	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Operating expenditure	125.0	122.5	132.3	142.4	156.3	525.0
Depreciation	91.2	100.9	109.2	117.8	129.6	422.7
Redundant assets (accelerated depreciation)	0.0	0.0	0.0	0.0	0.0	0.0
Return on investment	250.6	273.6	289.0	311.0	346.8	1,134.7
Return on working capital	1.2	3.0	3.7	3.6	3.2	11.3
Tax costs on capital contributions	10.6	10.7	10.9	11.0	11.4	42.5
Forward-looking efficient costs	**478.5**	**510.7**	**545.2**	**585.9**	**647.4**	**2,136.2**
Gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0.0
Unforeseen events revenue adjustment	0.0					0.0
Technical rule change adjustment	0.0					0.0
Investment adjustment mechanism	(47.4)					(43.6)
Service standards adjustment mechanism	(0.7)					(0.7)
D-factor	0.0					0.0
Recovery of current access arrangement deferred revenue	22.7	22.7	22.7	22.7	22.7	88.8
Total adjustments	**(25.5)**	**22.7**	**22.7**	**22.7**	**22.7**	**44.5**
Revenue cap correction factor	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Non-revenue cap services revenue	**(3.1)**	**(3.2)**	**(3.4)**	**(3.6)**	**(3.9)**	**(13.3)**
Maximum transmission reference service revenue unsmoothed	**449.9**	**530.3**	**564.5**	**605.1**	**666.2**	**2,167.4**
Maximum transmission reference service revenue smoothed	**486.5**	**523.7**	**559.2**	**597.3**	**638.2**	**2,167.4**

26 Revised access arrangement information, Section 13.2, Table 95.

Table 3 Western Power proposed distribution network target revenue (real $ million, at 30 June 2012)[27]

	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Operating expenditure	371.4	387.4	408.3	420.1	447.9	1,578.3
Depreciation	206.7	226.9	250.8	255.7	270.2	935.7
Redundant assets (accelerated depreciation)	3.4	0.5	0.0	0.0	0.0	3.6
Return on investment	375.5	407.0	444.3	480.9	514.4	1,713.6
Return on working capital	5.1	7.7	8.0	8.7	9.3	29.7
Tax costs on capital contributions	41.6	37.9	35.1	35.3	36.0	146.2
Forward-looking efficient costs	**1,003.7**	**1,067.4**	**1,146.4**	**1,200.7**	**1,277.8**	**4,407.0**
Gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0.0
Unforeseen events revenue adjustment	7.5					6.9
Technical rule change adjustment	0.0					0.0
Investment adjustment mechanism	2.0					1.8
Service standards adjustment mechanism	3.1					2.8
D-factor	0.0					0.0
Recovery of current access arrangement deferred revenue	170.7	170.7	170.7	170.7	170.7	667.2
Total adjustments	**183.3**	**170.7**	**170.7**	**170.7**	**170.7**	**678.7**
Tariff Equalisation Contribution	**181.2**	**180.7**	**180.8**	**181.7**	**182.5**	**708.6**
Revenue cap correction factor	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Non-revenue cap services revenue	**(14.9)**	**(15.3)**	**(16.0)**	**(16.8)**	**(17.9)**	**(62.8)**
Maximum distribution reference service revenue unsmoothed	**1,353.3**	**1,403.5**	**1,481.9**	**1,536.3**	**1,613.2**	**5,731.6**
Maximum distribution reference service revenue unsmoothed	**1,084.8**	**1,262.5**	**1,469.9**	**1,712.2**	**1,994.3**	**5,731.6**
Less TEC	(181.2)	(180.7)	(180.8)	(181.7)	(182.5)	(708.6)
Distribution revenue cap formula component	**903.7**	**1,081.7**	**1,289.1**	**1,530.5**	**1,811.8**	

189. Western Power has proposed smoothing the revenue cap based on a price path that continues the current access arrangement real increase in the average transmission

27 Revised access arrangement information, Section 13.2, Table 96.

tariff of 12.9 per cent from 2011/12 to 2012/13 and subsequent annual real increases in the remaining four years in third access arrangement period of 4.5 per cent (2013/14 to 2016/17). For distribution, Western Power proposes smoothing the revenue cap based on a price path that continues the current access arrangement real increase in the average distribution tariff of 16.3 per cent from 2011/12 to 2012/13 and subsequent annual real increases in the remaining four years in the third access arrangement period of approximately 11 per cent (2013/14 to 2016/17).[28]

Considerations of the Authority

190. The Authority's assessment of Western Power's determination of target revenue is documented in the following sections of this Draft Decision, addressing the following matters:

- forecasts of demand for services;
- forecast operating expenditure;
- amounts of actual and forecast capital expenditure and values of the regulated capital base at the commencement of the third access arrangement period and a notional regulated capital base over the term of the third access arrangement period;
- a return on the regulated capital base;
- taxation on capital contributions;
- an allowance for working capital; and
- adjustments to target revenue for the third access arrangement period to reflect certain cost and revenue outcomes for the second access arrangement period.

191. In considering Western Power's proposed target revenue, the Authority has made assessments of the actual and forecast costs of Western Power over the second and third access arrangement period.

Target Revenue

192. The Authority has determined values of target revenue for reference services taking into account determinations and required amendments of individual elements of target revenue as set out in this Draft Decision. The values of target revenue determined by the Authority are set out for the transmission and distribution networks in Table 4 and Table 5 below. These tables also show the "smoothed" target revenue that becomes the revenue cap under the price control.

[28] Revised access arrangement information, Section 13.3 Table 97.

Table 4 Authority's revised target revenue for the transmission network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Operating costs	100.1	99.2	100.9	103.6	107.5
Depreciation	86.4	93.9	102.4	107.8	113.8
Accelerated depreciation (redundant assets)	0.0	0.0	0.0	0.0	0.0
Deferred reference service revenue	10.9	10.9	10.9	10.9	10.9
Return on assets	100.4	107.7	117.8	121.6	126.1
Return on working capital	0.5	1.1	1.1	1.3	1.3
Total Gross Costs	**298.3**	**312.8**	**333.0**	**345.1**	**359.6**
Taxation	34.0	22.2	8.5	-	-
Imputation Credit	(8.5)	(5.5)	(2.1)	-	-
Investment adjustment mechanism	(48.2)	-	-	-	-
Service standard adjustment mechanism	(0.8)	-	-	-	-
Net costs after adjustments (unsmoothed)	**274.8**	**329.5**	**339.4**	**345.1**	**359.6**
Maximum forecast reference service revenue (smoothed)	**385.3**	**354.7**	**323.9**	**296.0**	**270.4**

Table 5 Authority's revised target revenue for the distribution network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Operating costs	330.0	331.9	337.4	335.1	346.0
Depreciation	197.1	215.3	236.7	239.1	251.0
Accelerated depreciation (redundant assets)	3.4	0.5	0.0	0.0	0.0
Deferred reference service revenue	81.7	81.7	81.7	81.7	81.7
Tariff Equalisation Contributions (TEC)	181.2	180.7	180.8	181.7	182.5
Return on assets	152.3	164.5	178.8	192.5	204.9
Return on working capital	2.3	2.7	2.8	2.9	3.0
Total Gross Costs	**948.0**	**977.3**	**1,018.4**	**1,033.0**	**1,069.2**
Taxation	31.8	40.6	46.8	59.6	58.6
Imputation Credit	(7.9)	(10.1)	(11.7)	(14.9)	(14.7)
Investment adjustment mechanism	1.9	-	-	-	-
Service Standard Adjustment Mechanism	2.0	-	-	-	-
Unforeseen Events Revenue Adjustment	7.2	-	-	-	-
Net costs after adjustments (unsmoothed)	**982.9**	**1,007.7**	**1,053.5**	**1,077.8**	**1,113.2**
Maximum forecast reference service revenue (smoothed)	**945.1**	**993.8**	**1,045.5**	**1,100.3**	**1,158.0**
Tariff Equalisation Contribution	181.2	180.7	180.8	181.7	182.5
Distribution reference service revenue (less TEC)	**764.0**	**813.1**	**864.6**	**918.6**	**975.4**

Required Amendment 4

The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in last row of Table 4 and Table 5).

193. Summary comparisons of the target revenue proposed by Western Power and that determined by the Authority under this Draft Decision are set out in Table 6, Table 7 and Table 8 below.

Table 6 Transmission network target revenue comparison: Western Power proposal and Draft Decision

	Western Power Proposal	Draft Decision
Present value of forecast reference service revenue ($ million)	$2,167.4	$1,466.5
Capital Expenditure previously disallowed as inefficient (real $ million)	$97.4	$0
Opening Capital Base for AA3 (real $ million)	$2,840.8	$2,593.2
Forecast Capital Base for AA4 (real $ million)	$4,209.8	$3,417.2
Capital Expenditure (real $ million)	$1,917.7	$1,328.3
Operating Expenditure (real $ million)	$678.6	$511.3
Present value of deferred revenue recovered ($ million)	$88.8	$48.6
Forecast average tariff increase 1 July 2012	CPI + 12.9%	CPI - 10.6%
Forecast average tariff increase 1 July 2013	CPI + 4.5%	CPI - 10.6%
Forecast average tariff increase 1 July 2014	CPI + 4.5%	CPI - 10.6%
Forecast average tariff increase 1 July 2015	CPI + 4.5%	CPI - 10.6%
Forecast average tariff increase 1 July 2016	CPI + 4.5%	CPI - 10.6%

Table 7 Distribution network target revenue comparison: Western Power proposal and Draft Decision

	Western Power Proposal	Draft Decision
Present value of forecast reference service revenue ($ million)	$5,731.6	$4,666.6
Capital Expenditure previously disallowed as inefficient (real $ million)	$147.1	$0
Opening Capital Base for AA3 (real $ million)	$4,257.2	$3,932.0
Forecast Capital Base for AA4 (real $ million)	$6,205.0	$5,599.1
Capital Expenditure (real $ million)	$3,162.1	$2,810.3
Operating Expenditure (real $ million)	$2,035.0	$1,680.5
Present value of deferred revenue recovered ($ million)	$667.2	$365.2
Forecast average tariff increase 1 July 2012	CPI + 17.6%	CPI + 2.5%
Forecast average tariff increase 1 July 2013	CPI + 13.4%	CPI + 2.5%
Forecast average tariff increase 1 July 2014	CPI + 13.4%	CPI + 2.5%
Forecast average tariff increase 1 July 2015	CPI + 13.4%	CPI + 2.5%
Forecast average tariff increase 1 July 2016	CPI + 13.4%	CPI + 2.5%

Table 8 Total transmission and distribution network target revenue comparison: Western Power proposal and Draft Decision

	Western Power Proposal	Draft Decision
Present value of forecast reference service revenue ($ million)	$7,899.1	$6,133.1
Capital Expenditure previously disallowed as inefficient (real $ million)	$244.0	$0.0
Opening Capital Base for AA3 (real $ million)	$7,098.0	$6,525.2
Forecast Capital Base for AA4 (real $ million)	$10,414.8	$9,016.3
Capital Expenditure (real $ million)	$5,079.8	$4,138.6
Operating Expenditure (real $ million)	$2,713.6	$2,191.8
Present value of deferred revenue recovered ($ million)	$756.0	$413.8
Forecast average tariff increase 1 July 2012	CPI + 16.4%	CPI - 1.0%
Forecast average tariff increase 1 July 2013	CPI + 11.1%	CPI - 0.7%
Forecast average tariff increase 1 July 2014	CPI + 11.2%	CPI - 0.4%
Forecast average tariff increase 1 July 2015	CPI + 11.4%	CPI - 0.1%
Forecast average tariff increase 1 July 2016	CPI + 11.5%	CPI + 0.2%

Forecast Demand for Services

Western Power's Forecast Demand

194. Western Power has forecast that over the third access arrangement period, the average annual growth will be:

- 146 MW per year (3.2 per cent) increase in peak demand compared with the average annual increase from 1998/99 to 2009/10 of approximately 147 MW.
- 2.4 per cent annual increase in the number of customers similar to the increase in the 2005/06 to 2010/11 period of 2.5 per cent per year.
- 2.8 per cent average annual increase in energy consumed by distribution-connected customers.

195. Western Power has based its third access arrangement period proposal on the November 2010 demand forecast, which is revised annually as part of the annual planning cycle. Western Power notes in the Access Arrangement Information that it does not anticipate that the November 2011 forecast will result in a material impact on its demand forecast.

Submissions

196. A submission from the West Australian Major Energy Users (**WAMEU**) acknowledges that while it does not have better data than Western Power in forecasting demand, it has observed 'that over time the error in the forecast of demand tends mainly to reflect a deferment of projects rather than projects being brought forward' and that the economic growth of the North West of Western Australia is likely to have biased the average State GSP above what is likely to occur in the South West. The WAMEU also considers that there is a strong incentive for demand side responsiveness to limit the growth in demand and that there needs to be careful assessment of forecast increases in demand.[29] Under a revenue cap form of regulation, there is an incentive for the regulated business to over-forecast demand to ensure higher approved expenditure amounts. WAMEU notes that Western Power's forecast consumption is below the levels implied by the Independent Market Operator (**IMO**) 2011 Statement of Opportunities, resulting in higher forecast tariffs per GWh.

Considerations of the Authority

197. The Authority notes that the risk of over-forecasting demand observed by WAMEU is partly addressed through the Investment Adjustment Mechanism which adjusts Western Power's target revenue at the next access arrangement review to take account of differences between actual and forecast expenditure in demand-related capital expenditure. However, it is important to ensure the robustness of the demand forecasts which is why Geoff Brown & Associates (**GBA)** was requested to assess some individual capital expenditure projects and programs for certainty and also whether there are non-network solutions.

---

29 Western Australian Major Energy Users, November 2011. *Electricity Distribution and Transmission Service in the Western Power South Western Interconnected System: Response to the Application*, pp 18.

198. Subsequent to Western Power's third access arrangement period proposal being submitted to the Authority, Western Power's 2011 Annual Planning Cycle Report has been released that indicates that peak demand will not increase as quickly as expected in the 2010 report.[30] The reduction in peak demand is a material change from forecasts in 2010 and GBA has noted that up to 40 per cent of Western Power's growth driven forecast transmission capital expenditure could be deferred to the fourth access arrangement based on these new forecasts.[31]

199. Load forecasting entails a level of uncertainty which is likely to be greater at a sub-regional level due to the correlation of localised peak demand not being as direct as for transmission capital expenditure. Consequently, GBA has proposed minor distribution capacity expansion should be reduced by 20 per cent rather than the 40 per cent adopted for transmission expenditure.[32]

200. After reviewing of all available information the Authority has formed the view that the most recent data available, being the 2011 Annual Planning Cycle Report, should be used for determining expenditure parameters.

201. Accordingly, all capital expenditure that is affected by the revised forecast peak demand calculations has been amended. These amendments are dealt with below.

Operating Expenditure

Access Code Requirements

202. Section 6.40 of the Access Code makes provision for the total costs and target revenue to include an amount in respect of forecast non-capital costs (operating costs) for the access arrangement period.

> 6.40 Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.

203. Sections 6.41 and 6.42 of the Access Code provide for the non-capital costs component of target revenue to include the non-capital costs of an "alternative option" of providing covered services, subject to certain conditions being met. An alternative option refers to an activity undertaken by Western Power for the purposes of providing a covered service as an alternative to investing in a major augmentation of the network, and may include such activities as demand-side management or generation either instead of, or in addition to, network augmentation.

> 6.41 Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option ("alternative option non-capital costs") if:

[30] Western Power, 2011 Annual Planning Report, http://www.westernpower.com.au/aboutus/publications/2011apr/index.html

[31] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 7.2.6, p. 80.

[32] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.3.5, p. 97.

(a) the alternative option costs do not exceed the amount of alternative option costs that would be incurred by a service provider efficiently minimising costs; and

(b) at least one of the following conditions is satisfied:

(i) the additional revenue for the alternative option is expected to at least recover the alternative option costs; or

(ii) the alternative option provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or

(iii) the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

6.42 For the purposes of section 6.41(b)(i) "additional revenue" for an alternative option means:

(a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the alternative option not been undertaken); minus

(b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs (other than alternative option costs) directly attributable to the increased sale of the covered services (being the covered services referred to in the expression "increased sale of covered services" in section 6.42(a)),

where the "rate of return" is a rate of return determined by the Authority in accordance with the Code objective and in a manner consistent with this Chapter 6, which may be the rate of return most recently approved by the Authority for use in the price control for the covered network under this Chapter 6.

Forecast Operating Expenditure

204. Western Power has forecast total operating expenditure (non-capital costs) of $2,713.6 million (real dollars at 30 June 2012) over the five year third access arrangement period, with $678.6 million required for the transmission network and $2,035.0 million for the distribution network. A breakdown of these amounts, together with the forecasts and estimated actual costs for the current access arrangement period are shown in Figure 2 and Figure 3.

Figure 2 Transmission network operating expenditure (real $ million at 30 June 2012)[33]

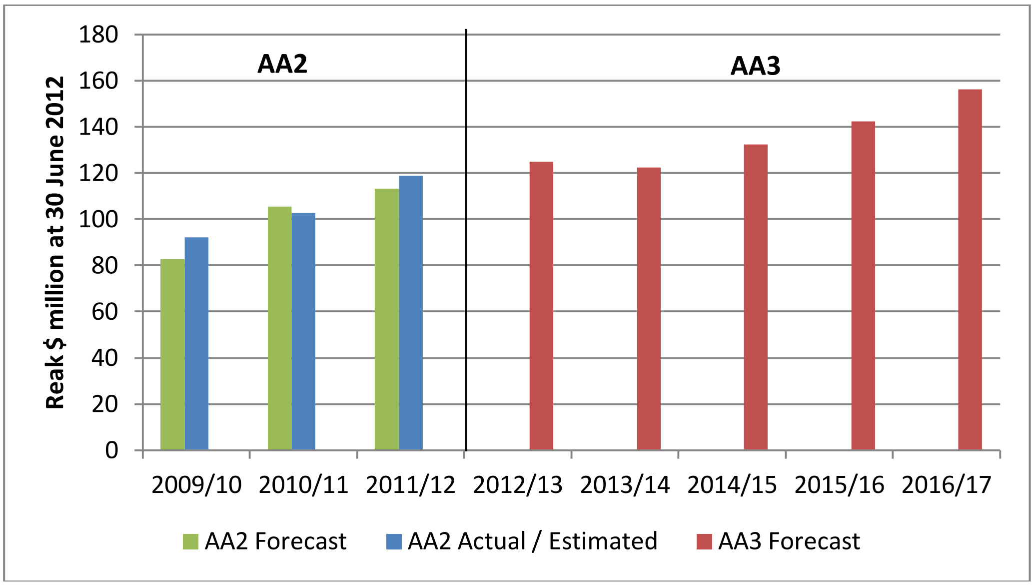
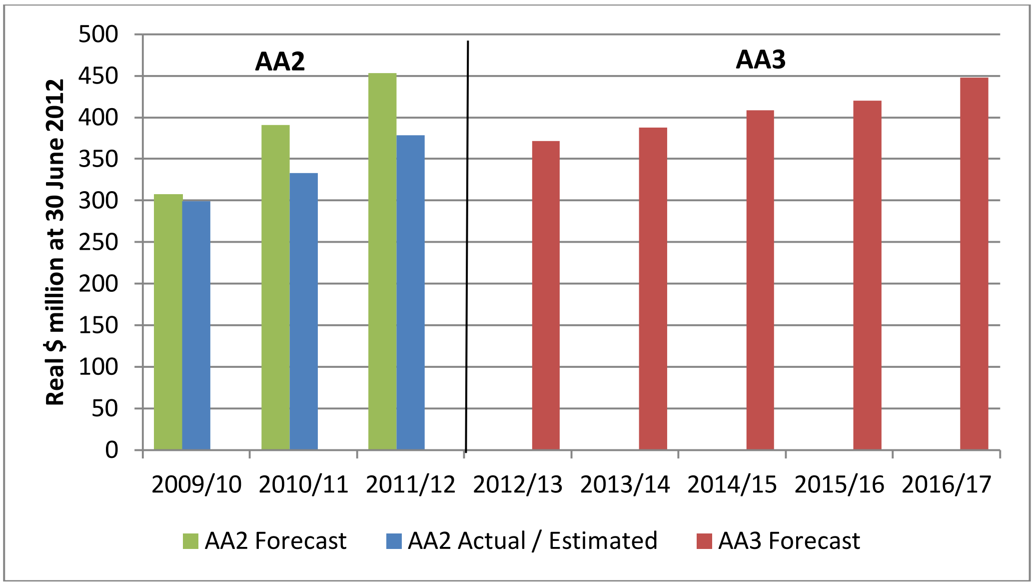


Figure 3 Distribution network operating expenditure (real $ million at 30 June 2012)[34]



205. Western Power has provided supporting information for its forecasts in Section 7 and Appendix A of the revised access arrangement information.

206. Western Power's actual operating expenditure for the current access arrangement period (in real dollar terms) was around 4 per cent in excess of the forecast (in real

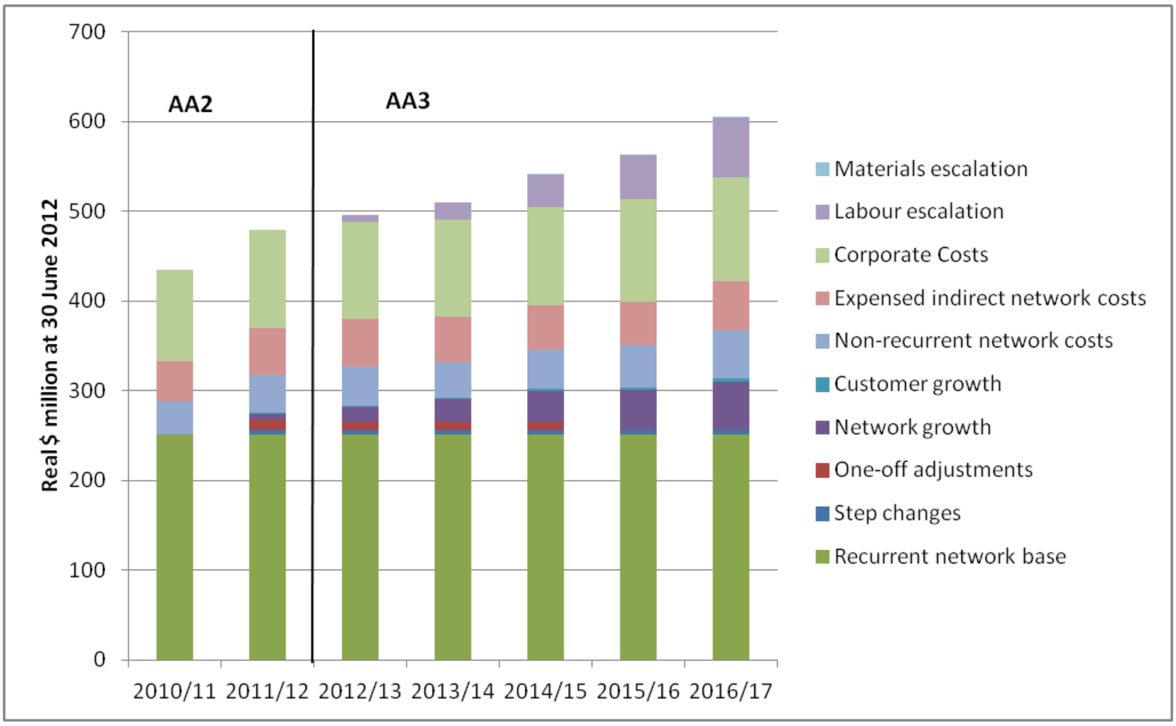
[33] 4 December 2009, Economic Regulation Authority, Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network; Revenue Model; and Revised access arrangement information for AA3.

[34] 4 December 2009, Economic Regulation Authority, Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network; Revenue Model; and Revised access arrangement information for AA3.

dollar terms) for the transmission network, but 12 per cent below the forecast for the distribution network.

207. Western Power has forecast its recurrent operating expenditure assuming that 2010/11 was an efficient base year and has maintained that cost in real terms across the forecast period. As shown in Figure 4 below, Western Power has then added to recurrent expenditure by including costs for step changes, one-off adjustments, network growth and customer growth. With the exception of $0.3 million per annum relating to savings gained by combining certain projects, Western Power has not assumed any future efficiencies in its forecasts.

Figure 4 Components of total operating expenditure for transmission and distribution network (real $ million at 30 June 2012)[35]



208. Western Power has forecast substantial real increases in operating expenditure over the actual costs incurred in the current access arrangement period, with the forecast level of operating expenditure in 2016/17 around 33 per cent higher than the actual level in 2010/11. The most significant increases in forecast operating expenditure relate to:[36]

- growth in the size of the network and customer numbers;
- forecast movements in real labour costs; and
- non-recurring costs for network control services, the introduction of new technologies, the field survey data capture project and removal of transmission lines that are no longer in service.

[35] Revised access arrangement information, Section 7.2, Table 27.

[36] Revised access arrangement information, Section 7.1, p. 129.

Submissions

209. Submissions on Western Power's forecast operating costs are addressed below under "Considerations of the Authority".

Considerations of the Authority

210. Under section 6.40 of the Access Code, the Authority must be satisfied that the forecast operating costs for the third access arrangement period include only those costs that would be incurred by a service provider efficiently minimising costs.

211. Western Power has proposed forecasts of operating expenditure that embody significant real increases over actual costs in the current access arrangement period in almost all categories of expenditure. Table 9 below sets out Western Power's proposed operating expenditure.

Table 9 Western Power's Proposed Operating Expenditure (real $ million at 30 June 2012)

Expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 Total
Recurrent network base	251.8	251.8	251.8	251.8	251.8	251.8	251.8	1,259.1
Step changes		4.0	5.0	5.0	5.0	5.0	5.0	25.0
One-off adjustments		11.5	8.7	8.7	8.7			26.1
Network growth		7.3	16.4	25.2	34.3	43.6	53.0	172.5
Customer growth		0.6	1.3	1.9	2.6	3.3	4.0	13.1
Total recurrent network costs	**251.8**	**275.2**	**283.2**	**292.6**	**302.4**	**303.7**	**313.9**	**1,495.8**
Non-recurrent network costs	**36.0**	**42.3**	**42.9**	**38.6**	**42.9**	**47.0**	**52.9**	**224.4**
Expensed indirect network costs	44.9	52.2	54.3	51.3	50.2	48.3	54.9	259.1
Corporate costs	**102.5**	**109.3**	**107.9**	**107.6**	**109.8**	**114.3**	**116.2**	**555.9**
Input cost escalation			8.1	19.7	35.2	49.1	66.3	178.4
Total AA3 operating expenditure[37]	**435.3**	**479.0**	**496.4**	**509.9**	**540.6**	**562.5**	**604.2**	**2,713.6**

Source: Western Power's Access Arrangement Information, Table 27.

212. The Authority has approached the forecast of operating expenditure by first considering the levels of expenditure during the second access arrangement period.

[37] Western Power has included expenses for non-revenue cap services of $98.1 million in non-recurrent network costs and this is also included in total AA3 operating expenditure. Western Power then deducts this non-revenue cap expenditure from target revenue.

The focus of the Authority's consideration of forecasts of operating expenditure has been, firstly, to consider whether the most recent recorded actual operating expenditure for the second access arrangement period (i.e. the year 2010/11) is consistent with the costs that would be incurred by a service provider efficiently minimising costs and, secondly, whether Western Power has adequately substantiated and justified differences in forecast operating expenditure from the actual operating expenditure incurred in that year.

213. The process adopted by the Authority in considering the forecasts of operating expenditure has therefore been to:

- verify records of actual operating expenditure for the first two years of the second access arrangement period for which actual cost data are available (2009/10 and 2010/11);
- assess the extent to which the actual operating expenditure for the current access arrangement period is efficient and consistent with the requirements of section 6.40 of the Access Code in order to establish an efficient level of base operating expenditure; and
- assess whether Western Power has provided adequate justification for forecast trends and step changes in levels of operating expenditure over the term of the third access arrangement period.

Verification of Operating Costs in the Second Access Arrangement Period

214. In accordance with the Authority's *Guidelines for Access Arrangement Information*[38], Western Power has provided regulatory accounts that reconcile costs of regulated activities with a set of base accounts for the business.[39] These regulatory accounts provide the following reconciliation of claimed operating costs with recorded operating costs.

Table 10 Reconciliation of claimed operating expenditure for 2009/10 and 2010/11 with recorded operating expenditure for the Western Power business (real $ million at 30 June 2012)

Network and Year	Base Account	Adjustments	Regulatory Account	Claimed non-capital costs	Access Arrangement Forecast
Transmission 2009/10	86.0	6.2	92.2	92.2	82.6
Transmission 2010/11	113.4	-10.8	102.6	102.6	105.4
Distribution 2009/10	289.2	9.8	299.0	299.0	307.3
Distribution 2010/11	327.5	5.9	333.3	333.3	390.8

215. The adjustments include:

- In 2009/10 the reclassification of the cost of unregulated fleet and regulated information technology depreciation as regulated operating expenditure costs (via the approved works program) and not depreciation and amortisation.

[38] 6 December 2010, Economic Regulation Authority, *Electricity Networks Access Code 2004 Guidelines for Access Arrangement Information (Version 2)*.

[39] 30 September 2011, Western Power, *Proposed Revisions to Access Arrangement – Access Arrangement Information Appendix G & Appendix H*.

- In 2010/11 the reclassification of depreciation as operating expenditure to offset the credit (from business unit charge recovery) in Corporate operating expenditure costs and to reverse the 2010/11 statutory write down for cancelled/deferred capital projects.

216. The Authority observes that the regulatory accounts presented by Western Power were audited for Western Power by the Office of the Auditor General. The Authority has had the regulatory accounts independently reviewed[40] and is satisfied that the regulatory accounts provide a true and correct indication of operating costs in 2009/10 and 2010/11.

217. However, the Authority notes the comments in BDO's report which indicates Western Power and System Management are yet to finalise the Ring Fencing Guidelines for System Management.[41]

Operating Costs in the Second Access Arrangement Period

218. The Authority has considered whether the actual operating costs for the current access arrangement period are consistent with a service provider efficiently minimising costs and therefore constitute a relevant cost base against which forecasts of non-capital costs for the third access arrangement period can be assessed.

219. Submissions from a number of interested parties were concerned with Western Power's choice of base year and to what extent it had been reviewed and adjusted to ensure only efficient costs were included.[42] Submissions also commented on the underspend during the second access arrangement period in relation to the forecasts included in target revenue at the second access arrangement review.

220. From a review of the benchmarking of Western Power against other Australian electricity networks, the WAMEU's indication is that Western Power is generally more expensive than its comparators, as in most cases its current performance is above the line of average performance. WAMEU noted that most similar businesses are lower cost performers than Western Power. WAMEU considers that the data provided by Western Power shows that the performance for the third access arrangement period will be more expensive than the current performance, reinforcing the view that the claimed operating expenditure is considerably higher than it needs to be.

221. In reviewing the forecast operating expenditure for the third access arrangement period, the Authority sought advice from GBA.[43] GBA has assessed the efficiency of Western Power's base year (2010/11) operating expenditure by:[44]

    - reviewing the incentives for Western Power to minimise its operating expenditure;

---

[40] March 2012, BDO, *Agreed Upon Procedures Engagement – Western Power's Access Arrangement for the South West Interconnected Network*.

[41] March 2012, BDO, *Agreed Upon Procedures Engagement – Western Power's Access Arrangement for the South West Interconnected Network*, Section 2.6, p. 36.

[42] WALGA, Alinta, WAMEU.

[43] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*.

[44] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3, p. 114.

- benchmarking the base year operating expenditure against operating expenditure reported by other network service providers in Australia; and
- reviewing individual base year operating expenditure line items (at a high level) for reasonableness.

Incentives to Minimise Operating Expenditure

222. GBA considered that there was an incentive for Western Power to minimise its base year operating expenditure (since it can retain any underspend for a given year as profit) but that this incentive was not as strong as intended due to the requirements of the gain sharing mechanism not being met during that year.[45] The approved gain sharing mechanism allowed Western Power to retain operating expenditure efficiency for a five year period (see section on Adjustments to Target Revenue in the Next Access Arrangement Period).[46] The gain sharing mechanism does not apply if service standard benchmarks are not met in a given year. Western Power did not meet a small number of service standard benchmarks in both 2009/10 and 2010/11, and is not expecting to meet a few benchmarks in 2011/12. As a result, Western Power will not receive any reward from the Gain Sharing Mechanism even though Western Power has significantly underspent the approved current access arrangement period operating expenditure levels.

223. GBA noted that in using Western Power’s proposed scale escalation model to forecast operating expenditure, a higher base year operating expenditure assessment will result in larger cost increases in each year of the access arrangement.[47] This is because escalators are applied to a higher starting amount and this is compounded over the period, which is why it is very important to ensure the base year operating expenditure is appropriate. GBA also noted that the asymmetrical gain sharing mechanism (there is no carry-forward penalty if there is an overspend), may create a perverse incentive for a service provider to increase operating expenditure to inefficient levels, particularly at the end of the regulatory period in the hope that this will lead to an increase in the regulatory operating expenditure provision in the next access arrangement period.[48]

224. The Authority considers there is some merit in adopting a symmetrical Gain Sharing Mechanism. However, if costs are higher than the approved amount but for valid reasons, such a mechanism may lead to the service provider being penalised unfairly. The Authority does not consider there is a need at this stage to make the mechanism symmetrical.

225. The Authority considers Western Power had some incentives to efficiently minimise operating expenditure by virtue of the incentive properties of the revenue cap price control applying under the current access arrangement. That is, Western Power would had an incentive to seek efficiencies in operating costs due to an ability to retain the benefits of cost savings relative to the forecasts on which the price control was set, and also due to Western Power being exposed to the risk of cost overruns

[45] March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, Section 10.3.1.1, p. 114.

[46] Also, Western Power’s current access arrangement requires all service standard benchmarks to be met in a given year in order for the gain sharing mechanism to apply.

[47] March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, Section 10.3.1.1, p. 114.

[48] March 2012, Geoff Brown & Associates, *Technical Review of Western Power’s Proposed Access Arrangement for 2012-2017*, Section 10.3.1.1, p. 114.

relative to the forecasts. However, the Authority agrees with GBA's view that the incentive properties inherent in the revenue cap price control under the current access arrangement could have been stronger.

Benchmarking Analysis

226. GBA undertook a benchmarking exercise of Western Power's base operating expenditure (2010/11) against the latest available operating expenditure levels recorded in other States. Due to differences in the manner in which Western Power classifies transmission and distribution assets compared with counterpart businesses in the rest of Australia, the benchmarking was carried out by combining the services.

227. Since the size of the networks in the different states differ, there was a need to normalise the performance for comparative purposes. The AER publishes an annual Electricity Performance Report for transmission service providers in which it uses line length and capital base value as normalisers. Both of these normalisers are also used for distribution networks along with a common distribution normaliser of customer numbers. GBA decided to use three normalisers – operating expenditure per km of line length, operating expenditure per customer and operating expenditure as a percentage of the regulated asset base – for comparative purposes. While GBA has cautioned that its analysis did not use a fully consistent data set, it is 'confident that the benchmarking is sufficiently accurate to be indicative of the relative efficiency of the electricity network operation in all the States considered.'[49]

228. The Authority notes that the three chosen normalisers differ slightly from the ones used by Western Power in its access arrangement information in which it chose peak demand, line length and customer numbers. Peak demand was not considered by GBA as network companies are essentially asset managers and a high proportion of their operating expenditure is maintenance related. The Authority agrees with this assessment and considers that the three normalisers chosen by GBA are the most valid for operating expenditure benchmarking for Western Power.

229. Also, the Authority considers that GBA's benchmarking analysis is superior to Western Power's benchmarking due to the definitional issues with regards to categorising transmission and distribution expenditure. While Western Power has noted that it has tried to reallocate to replicate its peers definitions of transmission and distribution, GBA's benchmarking does not rely on aligning the definitions and avoids any errors as a result of realignment. Also, GBA's benchmarking analysis has been based on the most recent available data, whereas Western Power's analysis uses a three year average to 2008/09 for transmission and the point estimate of 2009/10 for distribution.

230. The result of GBA's benchmarking analysis is shown in Table 11 below.

[49] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 115.

Table 11 Geoff Brown & Associates Operating Expenditure Benchmarking Results (real $ million at 30 June 2012)

Network	Opex/km line	Opex/Customer	Opex/RAB (%)
Western Power	4,507	433	7.2%
Queensland	4,053	436	4.2%
New South Wales	4,814	409	6.0%
Victoria	3,900	248	6.1%
South Australia	2,724	309	5.7%
Tasmania	3,965	407	5.0%

Source: Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017,* www.erawa.com.au, p. 115.

231. GBA concludes that Western Power does not perform well on any of the benchmarks in comparison with other States and that the results indicate that efficiency gains are available.[50]

232. GBA considers that capturing any efficiency gains which may be available to Western Power could take time and, therefore, it is more reasonable to capture these efficiency gains by incorporating an efficiency factor into the forecast operating expenditure for the third access arrangement period rather than apply an immediate adjustment to the base year expenditure.[51]

233. As noted in paragraph 220 above, a submission from the WAMEU included benchmarking that it had undertaken. Based on this work, the WAMEU considers that Western Power is generally more expensive than its comparators, as in most cases its current performance is above the line of average performance.

234. The Authority notes the benchmarking analysis undertaken by GBA and the submission from the WAMEU and is concerned with the performance of Western Power compared to the comparators. The Authority agrees with GBA that there should be efficiency gains available to Western Power and that an efficiency factor should be incorporated into the forecasts of operating expenditure. While there would be an argument that a global adjustment to the base year operating expenditure could be applied, the Authority considers that, in this case, it is best to incentivise Western Power to meet more efficient operating expenditure levels through *ex ante* adjustment. This will be discussed further in paragraphs 304 to 316.

235. While not directly related to the consideration of base year operating expenditure for the third access arrangement period, the Authority is concerned about the relative difficulty in undertaking benchmarking analysis between Western Power and its peers in Australia. While the usefulness of benchmarking has been a perennial issue in regulation of natural monopolies in Australia before and since the inception of incentive-based regulation in Australia, the issue seems to have received more focus of late.

---

[50] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.2, p. 115.

[51] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.2, pp. 115-116.

236. The Productivity Commission released an issues paper in February 2012, on its review of the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure in the NEM.[52] If there is a subsequent requirement for network service providers in the NEM to provide a set of consistent data to enable benchmarking, the Authority will make an assessment as to its applicability in Western Australia. In any case, the Authority is giving consideration to improvements in benchmarking analysis to be undertaken in future regulatory arrangements which is likely to include greater use of NEM comparators.

Line Item Analysis of Base Year Network Operating Expenditure

237. GBA undertook a high level review of individual line items included in the base year operating expenditure to identify base year expenditure line items that appeared to be atypical. GBA focussed on particular base year operating expenditure line items where the increase from 2009/10 was particularly large and sought further information from Western Power on the reasons for the increase. The individual base year operating expenditure line items which GBA identified as requiring further review are shown in Table 12 below.

Table 12 Western Power Current Access Arrangement Operating Expenditure Specific Line Items Identified by GBA for Further Review (real $ million at 30 June 2012)

Expenditure Item	2009/10	2010/11	Increase to 2010/11	2011/12
Distribution Corrective Maintenance – Emergency Follow-up Overhead Maintenance	3.8	8.4	120%	4.1
Distribution Corrective Deferred – Data Collection	0.9	3.3	267%	1.1
Distribution Preventive Condition – Earthing Maintenance	1.3	2.3	79%	1.7
Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency	4.6	7.1	54%	6.1
Transmission Corrective Deferred – Environmental Cleanup	0.3	1.2	308%	0.9
Transmission Preventative Condition – Plant and Building Refurbishment	0.3	1.4	417%	0.9
Transmission Substation Battery Maintenance and Inspections	1.4	1.7	21%	0.8
Transmission Substation Primary Plant	3.3	4.6	38%	4.9

Source: Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017,* www.erawa.com.au, pp. 116-121.

[52] February 2012, Productivity Commission, *Electricity Network Regulation: Issues Paper*.

238. GBA questioned the significant increase in the 'Distribution Corrective Maintenance – Emergency Follow-up Overhead Maintenance' line item for 2010/11 with Western Power. Western Power had noted that the 2009/10 amount was abnormally low due to an unexplained anomaly in the cost capture mechanism which led to work being incorrectly booked to the corrective emergency category. GBA reviewed this expenditure together with the corrective emergency category and concluded that this appeared to have been the case. As a result, GBA concluded that the base year expenditure was reasonable.[53]

239. Western Power appears to have included a one-off operating expenditure in the 'Distribution Corrective Deferred – Data Collection' line item. As a result, GBA has recommended a downward adjustment to the base year of $2.3 million to account for this.[54]

240. GBA notes that the decline in expenditure for the 'Distribution Preventive Condition – Earthing Maintenance' from 2010/11 to 2011/12 indicates that there is no need for the significant increase in expenditure in the base year to continue. As a result, GBA recommends an adjustment to revise base year operating expenditure to the 2011/12 level of $1.7 million (a $0.6 million adjustment).[55]

241. GBA considers that while expenditure for the 'Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency' is volatile, it is not valid to use the highest expenditure over the previous regulatory period for the scale escalation model. GBA proposes that the average annual expenditure in this category ($5.9 million) should be used as the base year operating expenditure amount. As a result, GBA recommends that base year operating expenditure be revised down by $1.2 million.[56]

242. Similarly, GBA considers that the 'Transmission Corrective Deferred – Environmental Cleanup' line item should be amended to reflect an annual average of the current regulatory period as it considers this line item is volatile. As a result, GBA recommends that base year operating expenditure be revised down by $0.4 million.[57]

243. GBA considers that Western Power has not provided a convincing reason why the higher level of expenditure for the 'Transmission Preventative Condition – Plant and Building Refurbishment' line item in 2010/11 should be maintained for third access arrangement period. As a result, GBA recommends that base year operating expenditure be revised down by $0.5 million to reflect the average annual expenditure over the second access arrangement period.[58]

---

[53] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.1, pp. 116-117.

[54] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.2, pp. 117-118.

[55] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.3, pp. 118-119.

[56] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.4, p. 119.

[57] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.5, p. 120.

[58] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.6, pp. 120-121.

244. GBA considers that the appropriate 2010/11 operating expenditure for 'Transmission Substation Battery Maintenance and Inspections' and 'Transmission Substation Primary Plant' line items should reflect the average annual expenditure over the current access arrangement period. As a result, GBA recommends that base year operating expenditure should be revised down appropriately (a total of $0.8 million).[59]

245. The Authority considers that the recommendations from GBA are justifiable and appropriate and therefore the base year (2010/11) operating expenditure for these line items should be adjusted to the amounts in Table 13 in order for the Access Code requirements to be met.

Table 13 Authority's Adjustments to Base Year Network Operating Expenditure for Line Item Review (real $ million at 30 June 2012)

Expenditure Item	Western Power's Proposed 2010/11	Adjustment required	Adjusted Cost 2010/11
Distribution Corrective Deferred – Data Collection	3.3	(2.3)	1.0
Distribution Preventive Condition – Earthing Maintenance	2.3	(0.6)	1.7
Transmission Substation Primary Plant Maintenance – Corrective Deferred and Emergency	7.1	(1.2)	5.9
Transmission Corrective Deferred – Environmental Cleanup	1.2	(0.4)	0.8
Transmission Preventative Condition – Plant and Building Refurbishment	1.4	(0.5)	0.9
Transmission Substation Battery Maintenance and Inspections	1.7	(0.5)	1.2
Transmission Substation Primary Plant	4.6	(0.3)	4.3
Total adjustment to Base operating expenditure		(5.8)	

246. Western Power's proposed recurrent network base year operating expenditure provided to GBA for review was slightly above its proposed amount in its revised Access Arrangement Information. The proposed recurrent network base year operating expenditure provided to GBA has been decreased by $5.8 million for the line-item adjustments outlined above. Adjustments were also made for the Authority's amended SCADA and communication, corrective works and efficiencies for bundling fuse pole clearing with vegetation inspections, which Western Power included as step changes (see discussion below). The Authority considers that the revised base year expenditure of $249.4 million to be a reasonable base upon which it can make an assessment of Western Power's proposed operating expenditure for the third access arrangement period.

[59] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.3.1.3.7, p. 121.

Table 14 Amended Base Year Network Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Recurrent Network Base – proposed[60]	252.4	252.4	252.4	252.4	252.4	1,262.0
Adjustment to proposed network base	(5.8)	(5.8)	(5.8)	(5.8)	(5.8)	(29.0)
Adjustment for SCADA and Communications	0.8	0.8	0.8	0.8	0.8	4.0
Adjustment for Corrective works	2.3	2.3	2.3	2.3	2.3	11.5
Adjustment for bundling fuse pole clearing with vegetation inspections efficiencies	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.5)
Recurrent Network Base – amended	**249.4**	**249.4**	**249.4**	**249.4**	**249.4**	**1,246.9**

Forecast Increases in Operating Expenditure

247. The method adopted by the Authority to assess Western Power's forecast of operating expenditure has been to consider differences from the level of operating expenditure actually incurred by Western Power in 2010/11, taking account of the adjustments noted in paragraphs 237 to 246 above. In considering differences between the forecast costs for third access arrangement and the adjusted actual costs of 2010/11, the Authority has had regard to information provided by Western Power in relation to:

- step changes in recurrent costs;
- one-off adjustments;
- network and customer growth;
- non-recurrent network costs;
- indirect network costs;
- corporate costs; and
- input cost escalation.

Step Change Adjustments

248. Step change adjustments are applied where scale escalation of base year expenditure is not a true reflection of the recurrent operating expenditure requirement for Western Power. Western Power has adjusted for step changes related to known future changes in practices, functions, obligations and operating environment. Step changes can either be negative, where costs incurred in the base year are no longer expected to be incurred in the future, or positive where recurrent costs that will be incurred in the future were not in the base year expenditure.

[60] Western Power's proposed base given to GBA following the revised access arrangement information indicated a network base operating expenditure of $252.4 million rather than $251.8 million as indicated in Western Power's revised access arrangement information. Base operating expenditure also excludes corporate expenditure.

249. GBA reviewed these adjustments and has recommended that the additional $0.8 million for SCADA and communications infrastructure and the decrease of $0.3 million for efficiency gains should be incorporated in base year operating expenditure. However, GBA recommends that $1 million cost for software licences should be treated as a one-off adjustment that occurs in each year of the regulatory period and not subject to scale escalation since this is a fixed cost. GBA considers that the expenditure associated with the amendments to the Metering Code should commence in 2012/13 instead of 2011/12 as proposed by Western Power. This is because the amendments to the Metering Code have yet to be drafted and gazetted and this is more likely to occur in 2012/13. GBA considered the total corrective expenditure for 2010/11 (base year), exclusive of indirect costs, and compared that to an amount with efficient escalation. GBA concluded that an increased amount of $2.3 million, rather than $3 million as proposed by Western Power, applied to the base year operating expenditure was appropriate to ensure a sustainable level of corrective works.[61]

250. The Authority considers the recommendations made by GBA to be well considered and appropriate and will include step adjustments for Western Power of:

- an additional $0.5 million from 2012/13 to increase the number of metering verifications and compliance testing expected from planned changes to the Metering Code.

251. The following adjustments will be considered as adjustments to the base year operating expenditure for modelling purposes:

- an increase of $0.8 million from 2011/12 for expenditure associated with additional SCADA and communications infrastructure;
- an increase of $2.3 million, rather than $3 million as proposed by Western Power, to ensure base year operating expenditure for corrective works represents a sustainable level of works; and
- a decrease of $0.3 million from 2011/12 to reflect efficiency gains by bundling fuse pole clearing with vegetation inspections and anticipated savings through the fires safe fuses program.

252. The Authority will consider the $1 million increase for software licences as a one-off adjustment that occurs in each year of the regulatory period, so as to not apply scale escalation to a fixed cost.

[61] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.4, p. 125-126.

Table 15 Authority's Adjustments to Step Changes in Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Step Changes – proposed	5.0	5.0	5.0	5.0	5.0	25.0
Adjustment for SCADA and Communications	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(4.0)
Adjustment for software licences	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(5.0)
Adjustment for Corrective works	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(15.0)
Adjustment for bundling fuse pole clearing with vegetation inspections efficiencies	0.3	0.3	0.3	0.3	0.3	1.5
Step Changes – amended	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**2.6**

One-off Adjustments

253. Western Power has proposed a one-off adjustment of $5.2 million in 2011/12 and $8.7 million per year over the three year period 2012-15 for transmission line pole inspection and maintenance to address the backlog of pole conditions to ensure safety and compliance outcomes. One-off adjustments are special non-recurring adjustments to recurring operating expenditure line items that are not subject to scale escalation. GBA understands that this proposed investment is related to additional work required as a result of an EnergySafety Order. GBA considers that the adjustments proposed by Western Power are reasonable.[62] The Authority agrees with the GBA assessment of this expenditure.

Table 16 Amended One-off Adjustment Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
One–off adjustments – proposed[63]	8.7	8.7	8.7	0.0	0.0	26.1
Adjustment for software licences	1.0	1.0	1.0	1.0	1.0	5.0
One-off adjustments – amended	**9.7**	**9.7**	**9.7**	**1.0**	**1.0**	**31.1**

Network and Customer Growth

Scale escalators

254. Western Power has proposed that its recurrent operating expenditure forecasts for the third access arrangement period be adjusted for a growing network and customer base. Western Power has proposed that an average annual network growth escalator be applied to network operations and maintenance activities and an average annual customer growth escalator be applied to call centre and metering activities. Western Power's calculation of the average annual growth rates, along with the actual growth rate from 2007/08 is demonstrated in Table 17.

---

[62] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.5. p. 126.

[63] Western Power's proposed base given to GBA following the revised access arrangement information indicated a network base operating expenditure of $252.4 million rather than $251.8 million as indicated in Western Power's revised access arrangement information. Base operating expenditure also excludes corporate expenditure.

Table 17 Western Power's Proposed Customer and Network Growth Escalation Data

	2007/08	2010/11	2016/17	Actual Growth Rate (2007-11)	Forecast Growth Rate (2010-17)
Customer Numbers (No)	937,104	1,006,430	1,162,284	2.41%	2.43%
Network Growth Escalators					
Line (km)	93,032	96,745	104,178	1.31%	1.24%
Distribution Transformers (No)	61,961	64,471	77,443	1.33%	3.10%
Zone Substation (MVA)	6,827	7,602	10,739	3.65%	5.93%
Average Network Growth Escalator				2.10%	3.42%

255. Western Power has adopted the parameters used by the AER for measuring distribution network size.[64] Western Power has also applied this escalation to its transmission expenditure. GBA considered that any error from applying this parameter to transmission operating expenditure is unlikely to be material.[65] The Authority agrees with this view expressed by GBA and considers that parameters selected by Western Power are sound.

256. Western Power's forecast customer number growth rate is slightly higher than the actual growth rate from 2007/08 to 2010/11. This difference is miniscule and as a result, the Authority does not see any justification to deviate from the historic customer growth rate of 2.41 per cent.

257. As highlighted in Table 17, Western Power has proposed escalators for the number of distribution transformers and zone substations which are significantly higher than the actual growth rate from 2007/08 to 2010/11. The growth in line length is comparable with the historic growth rate, and the Authority considers this forecast to be reasonable.

258. GBA reviewed the drivers of the number of distribution transformers – customer growth and, to a lesser extent, growth in distribution line length. Western Power forecast these drivers to be similar to historic levels. As a result, and with no explanation provided by Western Power for the significant increase in distribution transformers, GBA saw no basis for the acceleration in the annual rate of growth in distribution transformers proposed by Western Power.[66] The Authority accepts GBA's recommendation that there is no basis for an increase in the growth rate above the growth rate between 2007/08 to 2010/11.

259. GBA were unable to reconcile Western Power's forecast of a total of 3,137 MVA of new zone substation transformer capacity with Western Power's network development plan which indicated the addition of only 1,236 MVA over the period of 2010/11 to

[64] Western Power noted on p. 135 of its AAI that it used the number of feeders as a parameter. However, Western Power confirmed to GBA that it actually used the number of distribution transformers in its analysis.

[65] Marcg 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 122.

[66] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.1. p. 122.

2016/17.[67] The Authority notes that the implied average annual growth differs from that indicated in the network development plan (2.54 per cent) is well below Western Power's forecast of 5.93 per cent. This is also significantly lower than the actual growth rate from 2007/08 to 2010/11 (3.65 per cent).

260. The Authority also notes that Western Power has calculated an average annual network growth escalator over the period and used that in its model rather than the actual escalation factor for each year of the forecast period. Using an average rather than actual rate results in the forecast escalation being around $24 million greater than if the actual escalation had been used each year.[68] This arises because the implied forecast growth in assets is biased towards the end of the third access arrangement period. That is, Western Power has escalated the first few years above the implied growth rate in assets, which has a compounding benefit to Western Power.

261. Western Power has not applied a capital expenditure-operating expenditure trade off factor to its scale escalators. A trade-off arises when new assets require less maintenance than older assets. GBA considers an approach suggested by Nuttall Consulting Ltd in a report for the AER, to account for both the scale escalation of forecast asset growth and capital expenditure-operating expenditure trade-off by using actual growth rates for determining the escalation factor, to be a pragmatic and sound solution.[69] The rationale is that new assets installed have a honeymoon period during which little maintenance is required. This results in a lag between when assets are installed and when they must be inspected or maintained. In other words, the maintenance effort is driven not so much by the new assets installed but by the assets that were installed during the previous regulatory periods. This supports the GBA conclusion that the use of historic growth rates is appropriate.

262. In line with the discussion above, the Authority considers that the appropriate increase in the network growth escalator is 2.1 per cent. As the Authority has not accepted Western Power's forecast growth rates and has replaced them with its own assessment based on historical data, the overstatement noted in paragraph 261 has been removed.

Economy of scale

263. The scale escalation described above in paragraphs 254 to 262, reflects the increases in operating expenditure as a result of growth in the network. However, growth in the network should result in economies of scale, that is, lower total costs as a proportion of customers or energy demand or energy usage. Western Power has not included any provision for an economy of scale adjustment to modelling scale escalation. An economy of scale adjustment is an acknowledgement that as the network increases, the fixed component of operating expenditure will not increase as fast as the network increases. By not including an economy of scale adjustment, Western Power is assuming that fixed costs will increase at same rate as the network grows, which is an assumption that the Authority does not agree with. The AER has generally required provision for an economy of scale factor to be applied to operating expenditure

---

[67] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.1. p. 123.

[68] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*,Section 10.4.1. p. 123..

[69] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.1. p. 123..

forecasts using a scale escalation approach under which a higher percentage corresponds with a higher proportion of variable costs.

264. GBA reviewed past AER decisions on the appropriate factors, particularly for Powerlink and ETSA Utilities which used the same approach taken by Western Power to estimate its scale escalation model. GBA also took into account that Western Power operates an integrated transmission and distribution network. GBA considered that a factor of 30 per cent for network operations and 95 per cent for other costs was appropriate for Western Power.[70] The economies of scale factors are applied to the scale escalation to determine net escalation, discussed in paragraph 265. The lower the economies of scale factor (which would indicate a higher fixed to variable ratio), the lower the escalation applied to operating expenditure. The Authority considers that these economy of scale factors are reasonable estimates to be applied to Western Power's escalation model.

Amended scale escalation

265. Given the Authority's considerations above regarding the appropriate growth escalators and economy of scale factors, the Authority has applied the net growth escalators to operating expenditure as shown in Table 18.

Table 18 Authority's Approved Scale Escalators of Western Power's Recurrent Expenditure (per cent per annum)

	Growth	Economy of Scale	Net Growth
Distribution			
Network Operations	2.10	30	0.63
Reliability	2.10	95	2.00
SCADA and Communications	2.10	95	2.00
Maintenance – Corrective Deferred	2.10	95	2.00
Maintenance – Corrective Emergency	2.10	95	2.00
Maintenance – Preventative Condition	2.10	95	2.00
Maintenance – Preventative Routine	2.10	95	2.00
Call Centre	2.41	95	2.33
Metering	2.41	95	2.33
Transmission			
Network Operations	2.10	30	0.63
SCADA and Communications	2.10	95	2.00
Maintenance – Corrective Deferred	2.10	95	2.00
Maintenance – Corrective Emergency	2.10	95	2.00
Maintenance – Preventative Condition	2.10	95	2.00
Maintenance – Preventative Routine	2.10	95	2.00

266. The Authority has applied the net growth escalators to operating expenditure which amounts to $98.4 million over the third access arrangement period, as shown in Table 19.

[70] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.4.2. pp. 123-124.

Table 19 Amended Scale Escalation Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Network growth – proposed	16.4	25.2	34.3	43.6	53.0	172.5
Customer growth – proposed	1.3	1.9	2.6	3.3	4.0	13.1
Total scale escalation growth – proposed	17.7	27.1	36.9	46.9	57.0	185.6
Total scale escalation growth – amended	9.6	14.5	19.6	24.7	30.0	98.4

Scale Escalation Modelling Issues

267. GBA reviewed Western Power's scale escalation model and noted the following[71]:

- Western Power advised that it found an error in its inflation of 2010/11 expenditure into 2011/12 real dollars. GBA has corrected this error, which understated operating expenditure by about $3 million before the application of indirect costs and real cost escalation.
- GBA has corrected an error in Western Power's treatment of one-off expenditures in its model, as these amounts were escalated. GBA has removed escalation of these expenditures.

Non-recurrent Network Operating Expenditure

268. Western Power has forecast non-recurrent operating expenditure in its total forecast operating expenditure, as shown in Table 20. Non-recurrent operating expenditure includes activities that are one-off, project based or for a discrete time period. Western Power has not applied scale escalation to these costs.

[71] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.5. pp. 126-127.

Table 20 Western Power's Proposed Forecast of Non-recurrent Operating Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution – Smart Grid	4.3	3.5	4.2	5.5	6.7	24.3
Distribution – Field Survey Data Capture Project	5.6	7.2	7.2	7.1	7.2	34.3
Distribution – Network Control Expenditure	2.3	2.3	2.3	2.3	2.4	11.7
Distribution – Distribution Quotations	4.1	4.2	4.3	4.3	4.3	21.2
Distribution – GSL Payments	2.5	2.9	3.2	3.5	3.8	15.9
Distribution – Total	**18.8**	**20.1**	**21.2**	**22.7**	**20.6**	**107.5**
Transmission – Network Control Expenditure	10.8	4.5	9.4	12.1	17.7	54.5
Transmission – Transmission Line Decommissioning	2.9	2.4	0.7	0.6	-	6.6
Transmission – Total	**13.7**	**6.9**	**10.1**	**12.7**	**17.7**	**61.1**
Total non-recurrent operating costs	**32.5**	**27.0**	**31.3**	**35.4**	**38.3**	**168.6**
Non-revenue Cap Services						**90.2**
Indirect Costs included in line items above						**(34.4)**
Western Power's Non-recurrent Network Costs	**42.9**	**38.6**	**42.9**	**47.0**	**52.9**	**224.4**

Source: Western Power's response to GBA and Authority questions.

Smart Grid

269. Western Power has proposed to spend $24.3 million on operating costs for its smart grid program. The Authority received many submissions during the public consultation period in support of Western Power's proposed program.[72] The exceptions to this were opposing submissions from Synergy[73] and the Office of Energy[74]. Regardless of the level of support from interested parties, the Authority considers the investment should only be allowed if the benefits outweigh the costs. Western Power's forecast benefits include increased energy efficiency and the ability to "shift" load away from time of peak consumption which should increase the load factor and reduce the need for peaking generation. Most of the forecast benefits will

---

72 Goldfields-Esperance Development Commission, Lend Lease, Synergy, TPE Services, Mr Martin Anda, Verdant Vision, Denmark Community Windfarm Ltd, Silver Springs Networks Inc, Professor Peter Wolfs, Mr David Bryant, Sustainable Energy Now Inc, Professor Syed Islam, Sustainable Energy Association of Australia Inc, LandCorp, Mr Andrew Went, Water Corporation.

73 November 2011, Synergy, *Public Submission to the Economic Regulation Authority – Western Power's Proposed Revisions to the Access Arrangement.*

74 December 2011, Office of Energy, *Public Submission on the Issues Paper on Western Power's Proposed Amendments to its Access Arrangement for the Third Regulatory Period.*

accrue to customers through lower wholesale prices. GBA considered that the operating expenditure proposed by Western Power was reasonable.

270. GBA noted that it could be argued that the financial benefits to stakeholders of smart grid implementation have yet to be validated despite various trials and large scale roll outs in Australia. The Authority notes that smart metering infrastructure has attracted criticism in Australia particularly in relation to price rises resulting from the adoption of the technology. The Victorian advanced metering infrastructure program, in particular, has been quite contentious. GBA notes that Western Power appears to have learnt some of the lessons from the Victorian experience. The Authority notes that Western Power has forecast an NPV increase of $133 million in distribution operating expenditure despite field service savings (reduced meter reading etc) of $64 million over a 20 year horizon.

271. However, the Authority has considered the whole smart grid capital expenditure and operating expenditure program together and while speculative, benefits are estimated by Western Power to exceed costs by $208 million. The Authority has considered the capital expenditure amount for smart grid in paragraph 571.

272. GBA considered that, given Western Power's unique situation where it has the ability to leverage the replacement of 280,000 three phase meters, it considered that the smart grid deployment proposed by Western Power for the third access arrangement period is more likely than most to realise net stakeholder benefits over time. GBA noted that Western Power provided a very thorough analysis of potential benefits arising out of its proposed smart grid program and, while various modelling assumptions could be debated, the overall program does appear to offer a potentially promising net benefit to stakeholders. GBA considered that Western Power has been rigorous in forecasting the costs of the program and notes that it is proposing a relatively strong investment in consumer education to attempt to ensure that the wider stakeholder benefits are actually realised.[75]

273. While the additional expenditure is not entirely for the benefit of the distribution system, the new facilities investment test takes account of benefits to all those who generate, transport and consume electricity. The benefits identified by Western Power in relation to the smart grid program will accrue to such parties and therefore it is reasonably expected to meet the requirements of the new facilities investment test. As a result, the Authority will accept Western Power's proposed operating costs for smart grid during the third access arrangement period. However, as the Authority considers that these benefits are yet to be demonstrated, it will expect further information from Western Power on the realised benefits during the third access arrangement period to support any future proposals for additional expenditure in relation to extending the smart grid in the fourth access arrangement review or beyond.

Field survey data capture project

274. Western Power has proposed an amount of $34.3 million over the third access arrangement period is required to be spent on its field survey data capture project. This project is a continuation of a pilot project that was implemented in the current access arrangement. The project involves a complete survey of Western Power's

[75] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.1, p. 127, Section 8.9, p. 104.

transmission and distribution line assets and is aimed at addressing significant data quality issues.

275. GBA is unconvinced that the quality of the existing data set has deteriorated to the extent that the most extensive project of its kind ever undertaken in Australia is now required. GBA considered that a more targeted approach to fix areas where data is known to be poor should be considered by Western Power. GBA also noted that it would have expected Western Power's pilot project to have led to implementation efficiency gains but the extent to which such gains have been incorporated into its forecast expenditure is limited.[76]

276. As a result, GBA considers that half of the proposed expenditure should be sufficient. However, GBA noted that if Western Power considers this amount to be insufficient it should provide additional information following the Authority's Draft Decision.[77]

277. The Authority is concerned that Western Power's asset data is not of a high standard as Western Power is using this data set in some respects to set its expenditure forecasts. However, the Authority agrees that a more targeted approach of addressing areas where data is known to be poor should be considered by Western Power. As a result, and consistent with the requirement of section 6.40 of the Access Code, the Authority considers that 50 per cent of Western Power's proposed expenditure, is an appropriate forecast for distribution expenditure on the field survey data capture project. If Western Power considers this amount to be insufficient it will need to provide further justification to the Authority on why higher cost alternatives are required.

Table 21 Amended Forecast of Field Survey Data Capture Project Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Field Survey Data Capture Project – proposed	5.6	7.2	7.2	7.1	7.2	34.3
Field Survey Data Capture Project – amended	**2.8**	**3.6**	**3.6**	**3.6**	**3.6**	**17.2**

Network control expenditure

278. Western Power has included a forecast amount of $66.2 million of network control expenditure in its forecast operating costs during the third access arrangement period ($11.7 million on the distribution network and $54.5 million on the transmission network). Network control services are payments made to generators to operate at times of peak demand as a means to defer the need for capital expenditure in areas of network constraint. Western Power's targeted areas for network control services include Ravensthorpe and Bremer Bay on the distribution network and Albany, Geraldton, Eastern Goldfields and Pinjar on the transmission network.

[76] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section B5.5 pp. B16.

[77] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.2.1, pp. 127-128.

279. GBA has assessed Western Power's expenditure on these network control services and has noted that the uncertainties involved in forecasting these costs are much higher than other operating costs line items. This is due to the uncertainty of the cost of generation at the necessary time and the actual requirement for network control services on the actual demand for electricity.

280. However, as noted by GBA, this forecasting risk appears to fall entirely on customers, as Western Power can treat any under-expenditure as an efficiency gain and carry it forward into the fourth access arrangement period (as it is subject to the gain sharing mechanism) and for any over-expenditure, Western Power has indicated that it will seek to recover these costs under section 6.76 of the Access Code.[78]

281. The Authority considers that this approach is unreasonable as the forecasting risk falls asymmetrically. The Authority acknowledges that if there is a sound business case for this expenditure to defer capital expenditure, then it would be prudent for Western Power to undertake this expenditure. The Authority considers that no allowance should be included for network control services in forecast operating expenditure as it is not satisfied that it meets the test in section 6.40 of the Access Code and that Western Power should seek to recover any efficient operating expenditure it incurs on network control services through section 6.76 of the Access Code.

282. As a result, the Authority requires Western Power to remove its forecast operating expenditure in the third access arrangement period for network control services.

Table 22 Amended Forecast of Network Control Expenditure Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution – Network Control – proposed	2.3	2.3	2.3	2.3	2.4	11.7
Distribution – Network Control – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Transmission – Network Control – proposed	10.8	4.5	9.4	12.1	17.7	54.5
Transmission – Network Control – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Distribution Quotations

283. Western Power has included a forecast amount of $21.3 million for quotations on the distribution network. This expenditure is for the design and estimation of customer connection to the distribution network, as such it is customer driven and largely outside the control of Western Power. GBA recommended that the amount forecast by Western Power be accepted as the forecast requirement is lower than the average actual expenditure during the current access arrangement period.[79] The Authority acknowledges that this expenditure is largely outside of Western Power's control and, with expenditure below the average actual from the current access arrangement

[78] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.7.1, pp. 130-131.

[79] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.3, pp. 128-129.

period and without contrary information to the reasonableness of this forecast, it has decided to accept Western Power's forecast.

GSL Payments

284. Western Power has included a forecast amount of $15.9 million in its distribution operating expenditure for payments it is required to make under Part 3 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (NQ&RS Code). These payments are referred to as guaranteed service level payments (**GSL**). The payments relate to two quality of supply issues: non-notification of planned outages and extended outages.

285. The Authority acknowledges that Western Power is required by the NQ&RS Code to make guaranteed service level payments. However, the Authority considers that the payment relating to provision of notice for planned outages is fully within the control of Western Power's management and should not be borne by customers. Also, the Authority notes that Western Power actually pays more per instance of non-notification ($50) than legally prescribed ($20). As a result, the Authority requires Western Power to remove the amount for non-notification of planned interruptions.

286. Western Power is forecasting that the number of eligible customers for payments for extended outages (outages lasting longer than 12 hours) will increase significantly from 64,208 in 2010/11 to 180,521 by 2016/17. GBA notes that this is in spite of Western Power introducing a new $41.4 million capital expenditure program in the third access arrangement period to address the causes of extended supply interruptions. As a result, GBA considers that a more reasonable forecast would be to maintain the number of eligible customers at the 2010/11 amount. GBA has applied this to an average application rate of 30 per cent (not all eligible customers actually apply, with the application rate varying from 11 per cent to 37 per cent during the period 2006/07 to 2010/11). GBA has also suggested that a provision of 10 per cent of the determined requirement ($1.55 million based on the number of affected customers multiplied by the application rate and payment rate of $80) be allowed to fund additional payments for severe storms.[80] GBA has suggested this allowance for severe storms, e.g. for severe storm events similar to the event which occurred in March 2010, as Western Power's ability to mitigate the impact of these severe storms is limited. The number of customers eligible for 2010/11 payments did not include the impact for the severe storm on 22 March 2010.

287. The Authority considers that the forecasts calculated by GBA would reasonably reflect the efficient costs for GSL payments and as a result, requires that Western Power's operating expenditure is adjusted according to the amended forecast in Table 23.

Table 23 Amended Forecast of GSL Payment Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
GSL Payments – proposed	2.5	2.9	3.2	3.5	3.8	15.9
GSL Payments – amended	**1.7**	**1.7**	**1.7**	**1.7**	**1.7**	**8.5**

80 March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.6.4, p. 129-130.

Transmission Line Decommissioning and Removal

288. Western Power has included a forecast amount of $6.6 million in its transmission operating expenditure for the removal of approximately 60km of overhead line. GBA compared this proposed expenditure with the forecast decommissioning and removal costs of the existing 132 kV 190km long line between Pinjar and Eneabba as part of the Mid West Energy Project. The estimate for this cost is $6.01 million in real 30 June 2012 dollars. This estimate was only slightly below what Western Power is now forecasting for the removal of only 60km of line. GBA considered that a revised estimate of $2.1 million during the third access arrangement period was a reasonable estimate taking into account Western Power's forecast removal costs for the 190km line between Pinjar and Eneabba and then adding a 20 per cent margin to cover costs that may not be adequately provided for in a simple pro rata analysis. GBA's forecast also excluded real cost escalation.[81]

289. The Authority considers that the revised forecasts calculated by GBA would reasonably reflect the efficient costs for transmission line decommissioning and removal rather than what appears to be an excessive estimate provided by Western Power. As a result, the Authority requires that Western Power's operating expenditure is adjusted according to the amended forecast in Table 24.

Table 24 Amended Forecast of Transmission Line Decommissioning and Removal Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission line decommissioning – proposed	2.9	2.4	0.7	0.6	-	6.6
Transmission line decommissioning – amended	**1.0**	**0.8**	**0.2**	**0.2**	**-**	**2.2**

Summary of Non-recurrent Network Operating Expenditure

290. In summary, the Authority has amended Western Power's forecast for a number of new projects and programs which it has included in its forecast operating expenditure, as shown in Table 25. The Authority has excluded operating expenditure for non-revenue cap services from total operating expenditure. This approach has the same net result as Western Power's proposal which includes non-revenue cap operating expenditure in total operating expenditure and then deducts the same amount from revenue cap target revenue. The Authority considers excluding non revenue cap operating expenditure from the total operating expenditure forecast used to calculate target revenue is a simpler approach.

[81] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.7.2, pp. 131-132.

Table 25 Amended Forecast of Non-recurrent Operating Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Distribution – Smart Grid	4.3	3.5	4.2	5.5	6.7	24.3
Distribution – Field Survey Data Capture Project	2.8	3.6	3.6	3.6	3.6	17.2
Distribution – Network Control Expenditure	0.0	0.0	0.0	0.0	0.0	0.0
Distribution – Distribution Quotations	4.2	4.2	4.3	4.3	4.3	21.2
Distribution – GSL Payments	1.7	1.7	1.7	1.7	1.7	8.5
Distribution – Total	**12.9**	**13.0**	**13.8**	**15.1**	**16.4**	**71.3**
Transmission – Network Control Expenditure	0.0	0.0	0.0	0.0	0.0	0.0
Transmission – Transmission Line Decommissioning	1.0	0.8	0.2	0.2	-	2.2
Transmission – Total	**1.0**	**0.8**	**0.2**	**0.2**	**0.0**	**2.2**
Total non-recurrent operating costs	**14.0**	**13.8**	**14.0**	**15.3**	**16.4**	**73.5**

Indirect Cost Allocation

291. Western Power has included a forecast amount of $245 million in its operating expenditure forecasts for the third access arrangement period for indirect costs. Western Power has proposed an unexplained 17.3 per cent increase in the indirect cost allocation for operating expenditure between 2010/11 (base year) and 2012/13 (first year of the third access arrangement period). This compares to an average rate of growth in real indirect costs allocated to revenue cap operating expenditure over the current access arrangement period of 0.3 per cent.

292. GBA recommends that indirect costs, which should be largely fixed, should not be escalated by more than 0.63 per cent (the network operations net growth escalation factor). GBA has applied this annual escalation factor to the base year operating expenditure to determine the appropriate forecasts of indirect costs for the third access arrangement period. This adjustment implies a 13.7 per cent reduction in indirect costs allocated to operating expenditure.[82]

293. The Authority considers that GBA's recommendation is reasonable and has decided to reduce the amount of indirect costs allocated to operating expenditure by 13.7 per cent. As a result, the Authority requires Western Power to amend its forecast indirect costs allocated to operating expenditure to the amended amounts in Table 26.

[82] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.9, pp. 135-137.

Table 26 Amended Forecast of Indirect Cost Allocation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Indirect – Proposed (includes non-revenue cap services)	54.3	51.3	50.2	48.3	54.9	259.1
Indirect – Proposed (excludes non-revenue cap services	51.3	48.5	47.5	45.7	51.9	245.0
Adjustment (13.7%)	(7.0)	(6.6)	(6.5)	(6.3)	(7.1)	(33.5)
Indirect – Amended	**44.3**	**41.9**	**41.0**	**39.4**	**44.8**	**211.4**

Corporate Operating Expenditure

294. Corporate operating expenditure has been assessed separately from distribution and transmission costs. However, in determining target revenue, corporate operating expenditure is apportioned to the relevant revenue caps for distribution and transmission. Corporate operating expenditure is comprised of business support, insurance, rates and taxes, and the Energy Safety Levy. Western Power's proposed forecasts for corporate operating expenditure are shown in Table 27.

Table 27 Proposed Corporate Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Business Support	71.2	69.5	70.4	73.1	73.6	357.8
Insurance	25.9	26.8	27.4	28.3	29.1	137.4
Rates and Taxes	6.6	7.1	7.8	8.6	9.2	39.3
Energy Safety Levy	4.3	4.3	4.3	4.3	4.3	21.4
Total Corporate Operating Expenditure – Proposed	**107.9**	**107.6**	**109.8**	**114.3**	**116.2**	**555.9**

Business support expenditure

295. Western Power has included a forecast amount of $357.8 million in its operating expenditure forecasts during the third access arrangement period for business support costs. These costs relate to corporate service, strategy and finance, regulation and sustainability, legal and governance functions and the Office of the Chief Executive.

296. GBA has noted that the average annual expenditure of $71.6 million for the third access arrangement period is only 2.6 per cent higher than the average annual current access arrangement expenditure of $69.7 million.[83] The Authority has decided to allow Western Power's forecast business support expenditure as proposed. The Authority notes though that this is a 2.6 per cent annual average real increase and that Western Power will also apply real labour cost escalation to this amount. The Authority believes that this expenditure, which is mostly fixed in nature, should provide scope for Western Power to achieve efficiencies. The Authority will address this issue further in paragraphs 304 to 316.

[83] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.1, p. 132.

Insurance

297. Western Power has included a forecast amount of $137.4 million in its operating expenditure forecasts during the third access arrangement period for insurance costs. Western Power's proposed amount included workers compensation insurance costs, which are also included in other operating costs and an adjustment to correct for this error is necessary.

298. GBA has reviewed Western Power's insurance costs and, while not experts on insurance, have concluded that its forecast after the removal of workers compensation appears reasonable.[84] The Authority agrees with GBA's recommendation. Consequently, the Authority requires that Western Power's operating expenditure is adjusted to remove the workers compensation from the proposed insurance costs as these costs are included elsewhere and Western Power is required to amend its forecast costs in accordance with those in Table 28.

Table 28 Amended Forecast of Insurance Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Insurance – Proposed	25.9	26.8	27.4	28.3	29.1	137.4
Insurance – Amended	**22.9**	**23.6**	**24.0**	**25.0**	**25.9**	**121.4**

Rates and taxes

299. Western Power has included a forecast amount of $39.3 million in its operating expenditure forecasts during the third access arrangement period for the payment of rates and taxes. Western Power has forecast an increase in land-related taxes of 8 to 10 per cent and an increase in the fringe benefits by the increase in the works program as a proxy for an increased head count.

300. GBA considers that an 8 to 10 per cent nominal increase per year in land related taxes appears to be unsustainable over time but this was the advice Western Power had received from the Valuer General.[85] GBA was not in a position, and nor is the Authority, to propose an adjustment which is inconsistent with the Valuer General's advice.

301. However, Western Power's escalation of fringe benefits which is based on its works program assumes an increase in head count of around 30 per cent by the end of the third access arrangement period, which GBA considers as unlikely. GBA does not believe that the value of the approved works program is a valid proxy for headcount as much of the program is materials and much of the labour content is outsourced. A significant proportion of Western Power's internal labour is corporate support with this headcount relatively fixed. Given this, GBA considered that Western Power's 2010-11 base fringe benefit tax should be compounded annually by 2 per cent per annum.[86] The Authority supports the recommendation from GBA and considers a 2 per cent per annum increase to be reasonable. Western Power is therefore required to adopt the amended values in Table 29.

---

[84] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.2, p. 133.

[85] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.3, p. 134.

[86] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.3, p. 134.

Table 29 Amended Forecast of Rates and Taxes Costs (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Rates and Taxes – Proposed	6.7	7.1	7.8	8.6	9.2	39.3
Rates and Taxes – Amended	**6.7**	**7.0**	**7.4**	**7.9**	**8.4**	**37.3**

Energy Safety Levy

302. Western Power has included a forecast amount of $21.4 million in its operating expenditure forecasts for the third access arrangement period for its required payment of the Energy Safety Levy. As this payment is required and GBA notes that this is consistent with amounts paid in the current access arrangement period, the Authority will accept Western Power's forecast amount for the Energy Safety Levy.[87]

Amended Corporate Expenditure

303. In summary, the Authority will require Western Power to amend its proposed corporate operating expenditure to $538.0 million, as shown in Table 30.

Table 30 Amended Corporate Operating Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Corporate Operating Expenditure – Proposed	107.9	107.6	109.8	114.3	116.2	555.9
Adjustment to Insurance	(3.0)	(3.2)	(3.4)	(3.3)	(3.2)	(16.1)
Adjustment to Rates and Taxes	0.0	(0.1)	(0.4)	(0.7)	(0.8)	(2.0)
Corporate Operating Expenditure – Amended	**105.0**	**104.3**	**106.0**	**110.3**	**112.2**	**538.0**

Note: Some numbers do not add due to rounding.

Efficiency Adjustments

304. Western Power's operating expenditure forecasts have made no provision for progressively increasing the efficiency of Western Power's operating expenditure. The Authority notes that Western Power's submission to the Authority's Issues Paper states that Western Power has incorporated the efficiencies it initiated in the current access arrangement and which it expects to continue in the third access arrangement period into its forecasts. Western Power's submission believes the incentive properties in its proposed access arrangement would also provide the right incentives to seek further efficiencies in third access arrangement period. However, Griffin Power, Alinta, ERM Power and WALGA suggested that some level of future efficiency should be incorporated into Western Power's forecast operating expenditure.

[87] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.8.4, p. 135.

305. Griffin Power suggested Western Power should be benchmarked against other network providers to assess efficient expenditure and that there should be reductions in future price levels to encourage efficiency gains.[88]

306. Alinta questioned whether allowing overall operating expenditure to increase at the proposed level is consistent with a benchmark utility acting prudently and efficiently. Alinta suggested that Western Power should be subject to some level of base operating efficiency mechanism over the third access arrangement period, similar to the CPI-X framework of the National Electricity Rules.[89]

307. ERM Power noted that Western Power has not assumed any efficiency gains on base operating costs in its forecasts and believes that performance standards that result in efficiency increases are required and could be developed with external assistance.[90]

308. WALGA noted that Western Power's 2010/11 costs have been maintained in real terms and no efficiency gains on base operating costs are included, despite significant capital investment. WALGA considers Western Power should have efficiency improvement targets given the progress being made in technology and management and contracting practices.[91]

309. The benchmarking exercise undertaken by GBA indicated that there was scope for Western Power to achieve efficiency gains to improve its performance to the levels of its peers in Australia (see Table 11 for GBA's results). The GBA review of Western Power's governance procedures confirms that there is significant scope for efficiencies, especially in the areas of risk management, identification and evaluation of alternative options to meet a network development need and in improving asset databases.

310. In addition, GBA notes that the significant proposed capital investment by Western Power in modern and enhanced IT under the Strategic Program of Works (**SPOW**) program was approved by the Western Power Board on the basis of the operating efficiencies it will generate, yet none of the identified efficiencies expected in the third access arrangement period has been captured in Western Power's operating expenditure forecast.

311. Western Power's proposed IT projects to address issues with maintaining an up-to-date assets register should allow Western Power to leverage efficiency gains. In particular, GBA considers that the IT projects will help to provide the asset data needed to support the introduction of a structured condition based risk management (CBRM) system similar to that used by industry leaders. Currently, Western Power uses an informal CBRM system. However, GBA notes that businesses that have introduced a structured CBRM approach to maintenance planning have found significant cost savings. This implies that Western Power will have significant scope to achieve efficiency gains at relatively low cost.

---

88 November 2011, Griffin Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network*.

89 December 2011, Alinta Energy (Australia) Pty Ltd, *Public Submission on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network*.

90 December 2011, ERM Power Ltd, *Submission to the Economic Regulation Authority on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network* .

91 December 2011, Western Australasian Local Government Association, *Interim Submission - Proposed Revisions to the Access Arrangement for the Western Power.*

312. As Western Power is updating all of its main IT systems over a period of about seven years, this should increase efficiencies right across the business. Western Power is proposing to automate processes under its new IT systems which are currently done manually.

313. Overall, GBA considers that an annual efficiency target of 2 per cent should be readily achievable by Western Power.[92]

314. As noted in paragraph 296, the Authority believes that there should be scope for Western Power to achieve efficiencies in its business support costs, which Western Power has proposed will increase by, on average, 2.6 per cent annually.

315. Given the reasons stated above regarding the scope for Western Power to readily achieve an annual efficiency target during the third access arrangement period of 2 per cent, not to mention the scope of reducing business support costs and given that Western Power's governance is on an improving trajectory, which may result in the identification of further efficiencies, the Authority considers that a 2 to 3 per cent annual efficiency target should be achievable.

316. The Authority notes that the Western Australian Government's 2011/12 Budget required all government trading enterprises, including Western Power, to implement an efficiency dividend of 5 per cent each year from 2011/12 to 2014/15.[93] It could be argued that the Authority should make a similar efficiency assumption when determining forecast efficient operating costs. However, the Authority considers that a 2 to 3 per cent annual efficiency target for each year of the third access arrangement period, combined with the adjustments detailed in this section, would result in an appropriate balance between setting the efficient costs while providing Western Power a strong incentive to strive for further efficiencies. Any additional efficiencies achieved during the third access arrangement period will result in a lower operating expenditure base for the fourth access arrangement period which will benefit customers. For the purposes of this Draft Decision, the Authority had decided that a 2 per cent compound annual efficiency target, to apply from 2012/13 is reasonable. However, the Authority would welcome comment from interested parties on whether this 2 per cent efficiency target is adequate.

Table 31 Amended forecast operating expenditure with efficiency adjustment (real $ million at 30 June 2012)[94] [95]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Total – amended	432.5	434.2	440.3	440.6	454.3	2,201.9
Total – amended (-2%)	**423.8**	**417.0**	**414.5**	**406.5**	**410.7**	**2,072.4**

[92] March 2012, Geoff Brown & Associates 2012. *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 10.11.

[93] May 2011, Western Australian Government, *2011/12 Budget: Economic and Fiscal Outlook*, Budget Paper No.3, pp. 287-288.

[94] Amended transmission and distribution expenditure is allocated a portion of amended corporate operating expenditure based on the ratio of Western Power's proposed allocation of corporate expenditure to transmission and distribution in each year of the regulatory period.

[95] Amended transmission and distribution expenditure is allocated a portion of amended indirect operating expenditure based on the ratio of Western Power's proposed allocation of these costs.

Input Cost Escalation

317. The Authority has assessed Western Power's operating and capital expenditure exclusive of real input cost escalation, to assist with comparing the forecast changes in these expenditures over time.

318. Western Power has incorporated into both its proposed operating expenditure and capital expenditure forecasts, movements in the cost of labour and materials that will escalate at a rate above the CPI.

319. Western Power engaged the Competition Economists Group (CEG) and Macromonitors to provide forecasts of these escalation factors for the third access arrangement.

Labour escalation

320. Macromonitors provided forecasts for labour costs in the electricity, gas, water and waste services (EGWW) sector in Western Australia using three different measures – the average weekly ordinary time earnings (AWOTE), the wage price index (WPI) and unit labour costs (which accounts for productivity improvements).[96]

321. CEG provided a report on both labour and materials cost escalators and has used the forecasts provided by Macromonitors when determining its recommended labour cost escalation forecasts.[97]

322. CEG considered it reasonable to use actual measures of changes in staff costs where available, in preference to much broader measures for the entire EGWW sector. Therefore, salary increases outlined in the Western Power and (Communications Electrical Plumbing Union (**CEPU**) Collective Agreement 2008 have been used up to the final operation date of 1 October 2013. Forecasts provided by Macromonitors were used following 1 October 2013.

323. Of the three labour cost measures provided by Macromonitors, CEG decided to use the AWOTE measure when preparing the cost escalation calculations for Western Power. CEG noted that it used the AWOTE because it included the effects of compositional changes, including changes in the mix of skill categories and the mix of occupational categories with different pay scales.

324. CEG noted that it did not recommend the WPI because it excludes the effects of any compositional changes, including changes in the mix of skill categories or changes in the mix of occupation categories with different pay scales. The WPI assumes that the composition of the workforce will not change.

325. As has been used in recent AER final determinations in NSW and Tasmania a quarterly index was constructed by CEG to estimate forecasts when moving from forecasts based on Western Power + CEPU Union Collective Agreement 2008 which ends on 1 October 2013 and year ending June forecasts from Macromonitor.

[96] July 2011, Macromonitor, Access Arrangement Information – Appendix W2- *Macromonitor Report on Forecast Labour Costs.*

[97] September 2011, Competition Economists Group, Access Arrangement Information – Appendix W1- *CEG Report on Western Power Escalation Factors.*

326. In CEG's report a single labour cost escalation has been provided to Western Power rather than two escalation factors (an external and internal labour escalator) as proposed by Western Power in the current access arrangement. The single escalation factor combines both the internal labour costs with the external labour costs as CEG believes that both costs are driven largely by the same underlying factors.

327. Accordingly, Western Power has proposed the labour cost escalation factors, to be applied to both operating expenditure and capital expenditure, as listed in Table 32.

328. The WAMEU submission states that the Authority needs to define the basis on which it considers the setting of the expected inflation is the most appropriate, as Western Power's forecast is 0.2 per cent higher than what Powerlink has sought in Queensland, it is higher than the mid-point of the underlying inflation target of the RBA and the ABS has recently revised its calculation for headline inflation, which has resulted in a lower inflation rate.[98]

329. The WAMEU submission is very critical of the labour escalation above CPI proposed by Western Power.

330. The WAMEU submission recommended that the Authority should obtain an independent assessment of labour price movements such as the AER does, to ensure there is less opportunity for error and inbuilt conservatism being applied. The WAMEU submission observed that CEG has a preference for using AWOTE as the basis for labour cost price movements while the AER uses labour price indices in preference to those based on AWOTE.

331. The WAMEU submission was critical of Western Power's use of the EGWW labour index and considers the index will not reflect the labour cost of non-field staff such as office staff. WAMEU questioned the past and forecast productivity figures developed by Macromonitor for Western Power as the figures suggest productivity has fallen despite the supposed benefits of dis-aggregation and corporatisation of Western Power.

332. Western Power's proposal of an AWOTE measure for labour escalation is in contrast to Western Power's proposed use of a WPI during the current access arrangement which was supported by the Authority in its Final Decision.

333. Western Power's labour escalation factors based on the use of AWOTE also differs from recent decisions of the AER, including the final decision for Victoria Distribution Network Service Providers (**DNSP**) and draft decision for Queensland's Transmission Network Service Providers (**TNSP**).

334. The AER has preferred the use of a WPI as opposed to an AWOTE measure that was proposed by the DNSPs and TNSP in their respective proposals.

335. In the recent Victorian final decision the AER determined that:

"To the extent that the incentives within the regulatory framework assume current labour costs are efficient, the AER considers that satisfying both the NEL and NER requires compensating a DNSP purely for expected changes in the price of labour. That is, changes in the costs to a

---

[98] November 2011, Western Australia Major Energy Users, *Electricity Distribution and Transmission Service in the Western Power South Western Interconnected System: Response to Application.*

DNSP of employing labour, unaffected by compositional changes in the quality or quantity of work performed."[99]

336. The Authority is also of the view that if current labour costs are deemed to be efficient then Western Power should only be compensated for forecast changes in the price of that labour and should not be distorted with the addition of compositional changes.

337. Accordingly, the Authority considers that the cost escalation factors that should be applied to labour should be based on both the Western Power + CEPU Union Collective Agreement 2008 until its expiry on 1 October 2013 and then Macromonitors' WPI forecasts for the remainder of the third access arrangement period.

338. In calculating revised labour escalation factors, the Authority has used the same formula as set out in the CEG report. The formula used by CEG in the report was based on a similar formula used in previous decisions by the AER.

339. As noted in paragraph 337, as the Authority has accepted labour increases proposed by Western Power based its collective agreement until its expiry on 1 October 2013, the 2011/12 and 2012/13 labour escalators remain unchanged.

340. As a result of the collective agreement not expiring until 1 October 2013 (rather than on a financial year basis) the first quarter of the 2013/14 year will use the collective agreement wage increases and then for the remaining three quarters the Macromonitors' forecast WPI has been substituted into the calculations in place of the AWOTE to obtain a final cost escalation figure for that year.

341. In order to calculate the labour cost escalation amounts after the collective agreement expired for 2013/14, the Authority converted the annual collective agreement wage increases (running from 1 October to 30 September annually) into financial year percentages to ensure consistent comparison with Macromonitors' forecasts.

342. For the remaining 2014/15, 2015/16 and 2016/17 years, all four quarters of the financial year are based on Macromonitors' forecast WPI. Also, as was used by CEG in their calculations for Western Power, the Authority has also used a CPI of 2.5 per cent as a long term forecast for these years.

343. The revised labour cost escalation factors that result from using the Authority's approach are listed in Table 32.

Table 32 Amended real labour input escalation factors (per cent)[100]

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Labour Escalation – Proposed	1.9	1.5	3.1	3.7	3.1	3.1
Labour Escalation – Amended	**1.9**	**1.5**	**2.2**	**2.4**	**2.0**	**2.0**

[99] October 2010, AER, *Victorian electricity distribution network service providers determination 2011–2015.*

[100] September 2011, Western Power, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, p. 141.

Materials Escalation

344. Western Power has proposed real materials escalation based on CEG forecasts for the price of Steel, Copper, Aluminium and Oil. These forecasts are set out in Table 33.

345. The WAMEU submission is very critical of the materials escalation above CPI proposed by Western Power. The WAMEU submission contends that Western Power has only included those materials most likely to increase in value faster than CPI and has neglected to include materials which are expected to increase at a lesser rate.

346. The WAMEU submission is critical of the report by CEG for Western Power, which in its view, just provides conclusions for the materials identified by Western Power and provides little in the way of quantification and reasoning on how outcomes were achieved. The WAMEU submission noted that while crude oil was expected by Western Power to increase above inflation, crude oil futures are suggesting a decrease in price. The WAMEU submission also highlighted a lack of forecast movements in exchange rates provided in the CEG report. Overall, the WAMEU submission doubts that the approach used by Western Power is reasonable.

347. The WAMEU submission expressed an expectation that the Authority ensure that the overall allowance for materials escalation reflects the movements in all materials used by Western Power. The WAMEU submission also expressed concern that the materials escalation proposed by Western Power is too conservative and should be adjusted to remove conservatism. The WAMEU submission proposed that Western Power should be required to provide a statement as to the compounded error that is implicit in the final value used.

348. The Authority notes that Western Power has not adopted an escalation factor inclusive of price changes for zinc, although, the cost of zinc was generally forecast to increase over the period forecast by CEG. CEG provided a forecast for zinc at the request of Western Power in the terms of reference for the CEG report.

349. The Authority notes that Western Power did not include materials that were forecast to increase by less than CPI in determining an escalation factor for materials.

350. Also, the Authority notes that the forecast additional cost due to the materials escalation factors, in real dollar terms, is quite a small amount in the context of the total expenditure for the third access arrangement period.

351. The Authority is of the opinion that for the materials escalation costs calculated by Western Power, the negligible amount calculated as a cost escalation would most likely be offset by materials that will increase in cost at below the CPI, which did not form part of the forecast.

352. Accordingly, the Authority considers that the cost escalation factor that should be applied to materials is only the CPI and that Western Power should adjust all materials forecasts that have been escalated by recalculating these with a factor of 0 per cent above the CPI.

Table 33 Amended real materials escalation factors (per cent)[101]

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Steel – proposed	-1.3	-2.6	0.7	4.1	3.4	2.7
Copper – proposed	-5.3	-0.8	-0.8	-1.7	-2.4	-3.1
Aluminium – proposed	-0.9	2.8	4.1	3.9	3.3	2.6
Oil – proposed	-0.2	2.1	1.6	1.0	0.7	0.4
Steel – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Copper – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Aluminium – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Oil – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Operating Cost Escalation

353. The Authority has calculated a notional amount of real cost escalation for labour for Western Power based on its recommended escalation factors and for this Draft Decision has added this to the total distribution and transmission operating expenditure forecasts.

354. The Authority has calculated the notional amount of real cost escalation for labour by using a ratio of the index values proposed by Western Power compared with the amended indices calculated by the Authority, and applied this to Western Power's proposed dollar value of escalation for each year of the third access arrangement period.

355. The total impact of the labour escalation factors was forecast by Western Power to be \$177.5 million for operating expenditure[102] (calculated in real dollar terms at 30 June 2012). The Authority has amended this amount to \$129.7 million over the third access arrangement period.

356. The total impact of the materials escalation factors was forecast by Western Power to be \$0.9 million for operating expenditure[103] (calculated in real dollar terms at 30 June 2012). The Authority has not allowed for any materials escalation.

Table 34 Amended Real Input Escalation Factors (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Labour Escalation – Proposed Operating Expenditure	8.1	19.7	35.0	48.8	65.9	177.5
Labour Escalation – Amended Operating Expenditure	**8.1**	**16.0**	**25.8**	**34.5**	**45.3**	**129.7**
Materials Escalation – Proposed Operating Expenditure	-0.1	0.0	0.2	0.3	0.4	0.9
Materials Escalation – Amended Operating Expenditure	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

[101] Ibid, p. 142.
[102] Ibid, p. 140.
[103] Ibid, p. 140.

Required Amendment 5

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 32 and Table 33.

Transmission Network Operations Expenditure

357. It appears to the Authority, that Western Power has included some expenditure for network operations which should be apportioned to System Management. In section 3.2.2 of Appendix A of Western Power's revised access arrangement information, Western Power notes that its planning and market operations involves 'ensuring that market participants are compliant with the WEM [wholesale electricity market] Rules and that the (ring-fenced) System Management operates in accordance with the Market Rules.' This is a requirement of System Management and should be funded by it, rather than Western Power's customers. As a result, the Authority requires Western Power to remove all planning and market operations expenditure from this category of investment as it appears to relate to System Management responsibilities.

358. Also, the Authority considers that control centre administration and management expenditure will also relate to System Management responsibilities, for the purposes of this Draft Decision, the Authority has decided that only 50 per cent of the proposed expenditure should be allowed in Western Power's forecast operating expenditure.

359. If Western Power considers that it requires more of this expenditure for its operations rather than System Management's operations, then it should provide further information in its response to the Draft Decision.

360. As Western Power's forecasts included real input escalation, the Authority will remove this expenditure following addition of real input escalation in determining the forecast operating expenditure requirement for Western Power. Table 35 shows the Authority's required adjustment to operating expenditure forecasts.

Table 35 Amended Forecast of Planning and Market Operations and Control Centre Administration and Management Expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission Planning and Market Operations – proposed	1.4	1.5	1.6	1.7	1.9	8.2
Transmission Control Centre Administration and Management – proposed	0.8	0.9	0.9	1.0	1.1	4.7
Transmission Planning and Market Operations - Amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Transmission Control Centre Administration and Management – amended	**0.4**	**0.5**	**0.5**	**0.5**	**0.6**	**2.5**
Total Adjustment to Operating Expenditure	**(1.8)**	**(1.9)**	**(2.0)**	**(2.2)**	**(2.4)**	**(10.3)**

Source: Western Power's Access Arrangement Information, Appendix A, Table 12 and Authority's calculations

Total Operating Expenditure

361. Taking into account the consideration of the individual cost line items as set above, scale escalation, real cost escalation and other adjustments, the Authority considers that Western Power's forecasts of operating expenditure as set out in the revised access arrangement information are not consistent with the requirements of section 6.40.

362. Table 36 below sets out the Authority's amended operating expenditure forecasts.

Table 36 Amended Operating Expenditure (real $ million at 30 June 2012)[104]

Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 Total
Recurrent network base[105]	249.4	249.4	249.4	249.4	249.4	1,246.9
Step changes[106]	0.5	0.5	0.5	0.5	0.5	2.6
One-off adjustments	9.7	9.7	9.7	1.0	1.0	31.1
Growth escalation[107]	9.6	14.5	19.6	24.7	30.0	98.4
Total recurrent network costs	**269.2**	**274.1**	**279.2**	**275.6**	**280.9**	**1,379.0**
Non-recurrent network costs	**14.0**	**13.8**	**14.0**	**15.3**	**16.4**	**73.5**
Expensed indirect network costs	44.3	41.9	41.0	39.4	44.8	211.4
Corporate costs	**105.0**	**104.4**	**106.0**	**110.3**	**112.2**	**538.0**
Gross operating expenditure	**432.5**	**434.2**	**440.3**	**440.6**	**454.3**	**2,201.9**
Efficiency adjustment	**(8.6)**	**(17.2)**	**(25.9)**	**(34.2)**	**(43.6)**	**(129.6)**
AA3 operating expenditure	**423.8**	**417.0**	**414.5**	**406.5**	**410.7**	**2,072.4**
Input cost escalation	8.1	16.0	25.8	34.5	45.3	129.7
Adjustment for System Management expenditure	(1.8)	(1.9)	(2.0)	(2.2)	(2.4)	(10.3)
Total AA3 operating expenditure	**430.1**	**431.1**	**438.3**	**438.7**	**453.5**	**2,191.8**

363. Taking into account the individual cost line-items as set out above, the Authority considers that Western Power's forecasts of operating expenditure as set out in the revised access arrangement information are not consistent with the requirements of section 6.40. The Authority will require amendment of the revised proposed access arrangement so that the target revenue and price control reflect a forecast of operating expenditure as indicated in Table 37.

104 Revised Access Arrangement Information, p. 131.

105 Recurrent network base is calculated by adjusting the Authority's adjusted base year network operating expenditure with the modelling adjustments noted in the 'Step Change Adjustments' section.

106 The Authority has reallocated some step change adjustments requested by Western Power to the base operating expenditure and also one-off adjustments.

107 This includes both network and customer growth.

Table 37 Amended forecast operating expenditure (real $ million at 30 June 2012)[108] [109] [110]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission – proposed	125.0	122.5	132.3	142.4	156.3	678.6
Transmission – amended	**100.1**	**99.2**	**100.9**	**103.6**	**107.5**	**511.3**
Distribution – proposed	371.4	387.4	408.3	420.1	447.9	2,035.0
Distribution – amended	**330.0**	**331.9**	**337.4**	**335.1**	**346.0**	**1,680.5**
Total – proposed	496.4	509.9	540.6	562.5	604.2	2,713.6
Total – amended	**430.1**	**431.1**	**438.3**	**438.7**	**453.5**	**2,191.8**

Required Amendment 6

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure as indicated in Table 37.

---

108 Amended transmission and distribution expenditure is allocated a portion of amended corporate operating expenditure based on the ratio of Western Power's proposed allocation of corporate expenditure to transmission and distribution in each year of the regulatory period.

109 Amended transmission and distribution expenditure is allocated a portion of amended real input escalation based on Western Power's proposed allocation of transmission and distribution network operating expenditure.

110 Amended operating expenditure does not include operating expenditure for non-revenue cap services.

Opening Regulatory Capital Base for the Third Access Arrangement Period

Access Code Requirements

364. The capital base is the value ascribed to the network assets that are used to provide covered services. Where the target revenue for the price control is set by reference to the service provider's total costs, section 6.43 of the Access Code provides for the value of the capital base to be used to calculate a return on the capital base and an amount of depreciation.

365. Under the first access arrangement, an initial capital base was established under sections 6.46 and 6.48 of the Access Code at an "optimised deprival value" of the network assets.

366. Section 6.48 of the Access Code requires that the capital base at the start of any access arrangement period, other than the first access arrangement period be determined in a manner that is consistent with the Access Code objective. A note to section 6.48 indicates that:

> A number of options are available in relation to the determination of the capital base at the start of an access arrangement period, including:
>
> - rolling forward the capital base from the previous access arrangement period applying benchmark indexation such as the consumer price index or an asset specific index, plus new facilities investment incurred during the previous access arrangement period, less depreciation and redundant capital etc; and
>
> - valuation or revaluation of the capital base using an appropriate methodology such as the Depreciated Optimised Replacement Cost or Optimised Deprival Value methodology.

367. Notwithstanding that section 6.48 of the Access Code does not mandate a method of valuation of the capital base, sections 6.50 to 6.63 of the Access Code contemplate new facilities investment being added to the capital base and the value of any redundant assets being subtracted from the capital base, consistent with use of the "roll forward" method for determination of the capital base.

368. Section 6.51A of the Access Code provides that new facilities investment may be added to the capital base if it passes certain tests:

> 6.51A New facilities investment may be added to the capital base if:
>
> (a) it satisfies the new facilities investment test; or
>
> (b) the Authority otherwise approves it being adding to the capital base if:
>
> (i) it has been, or is expected to be, the subject of a contribution; and
>
> (ii) it meets the requirements of section 6.52(a); and
>
> (iii) the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of the addition.

369. The new facilities investment test is set out in section 6.52 of the Access Code:

6.52 New facilities investment satisfies the new facilities investment test if:

(a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:

(i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied;

or

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

370. The "modified test" referred to in section 6.52(b)(i)B of the Access Code and set out in section 6.53 provides for an access arrangement to specify that new facilities investment below a threshold value will not be subject to the tests of sections 6.52(b)(i)A, (ii) and (iii) of the Access Code.

371. Section 6.54 of the Access Code requires that the Authority, in making a determination under the new facilities investment test, must have regard to whether the new facilities investment was required by a written law or a statutory instrument.

372. Sections 6.61 to 6.63 of the Access Code provide for an amount to be subtracted from the capital base in respect of redundant network assets.

373. With proposed revisions to an access arrangement typically being considered by the Authority prior to commencement of the access arrangement period in which the revisions to the access arrangement will apply, the capital base at the start of the access arrangement period will need to be determined (if being determined by the roll-forward method) without knowledge of all the new facilities investment that will occur in the current access arrangement period. In this circumstance, section 6.50 of the Access Code provides for a forecast of the new facilities investment to occur prior to the revisions commencement date to be added to the capital base if, at the time of inclusion, it is reasonably expected to satisfy the test in section 6.51A.

Proposed Revisions

374. Consistent with the current access arrangement, Western Power has specified capital base values separately for the transmission and distribution networks.

375. The capital base values for each of the transmission and distribution networks have been calculated by Western Power for the beginning of the third access arrangement period using a roll-forward method that involves commencing with the opening value at the beginning of the second access arrangement period and:

- adding the actual (and estimated actual for 2011/12) values of capital expenditure (new facilities investment) during the second access arrangement period that Western Power considers to meet the requirements of the new facilities investment test under section 6.52 of the Access Code (excluding gifted assets and capital expenditure which is funded by customers via capital contributions);[111]
- deducting values of redundant assets;
- deducting values of depreciation as allowed for in target revenue for the second access arrangement; and
- making an adjustment for inflation to be expressed in dollar values at 30 June 2012.

376. Western Power has also included the following new additional adjustments in order to calculate the opening value at the beginning of the third access arrangement:

- included expenditure relating to inventory in the actual (and estimated actual for 2011/12) values of capital expenditure;
- adopted a mid-year timing assumption for capital expenditure; and
- added investment incurred in the first access arrangement, which the Authority determined to be inefficient, to the opening capital base for the third access arrangement period.

377. Western Power's calculated values of the capital base for the transmission and distribution networks (incorporating forecast values for 2011/12) at the commencement of the third access arrangement period (1 July 2012) are set out in Table 38 and Table 39 respectively below.

[111] Capital expenditure is added to the regulated capital base on an "as incurred" basis rather than an "as commissioned" basis.

Table 38 Transmission network capital base at 30 June 2012 (real $ million at 30 June 2012)[112]

	2009/10	2010/11	2011/12	2012/13
Opening asset value	**2,350.0**	**2,502.9**	**2,575.5**	**2,840.8**
Capital expenditure	225.6	147.6	193.8	-
Inventory			20.2	
Asset disposals	-6.0	-0.3	0.0	-
Depreciation	-75.3	-80.5	-91.1	-
Accelerated depreciation	0.0	0.0	0.0	-
Mid-year timing assumption	8.6	5.8	7.6	-
Investment from prior periods	-	-	135.0	-
Closing asset base	**2,502.9**	**2,575.5**	**2,840.8**	**-**

Numbers do not add up due to rounding.

Table 39 Distribution network capital base at 30 June 2012 (real $ million at 30 June 2012)[113]

	2009/10	2010/11	2011/12	2012/13
Opening asset value	**3,042.3**	**3,338.4**	**3,625.2**	**4,257.2**
Capital expenditure	438.8	441.8	544.5	-
Inventory			53.4	
Asset disposals	-0.9	0.0	0.0	-
Depreciation	-154.7	-168.2	-186.0	-
Accelerated depreciation	-4.2	-4.1	-4.0	-
Mid-year timing assumption	17.1	17.3	21.3	-
Investment from prior periods	-	-	202.8	-
Closing asset base	**3,338.4**	**3,625.2**	**4,257.2**	**-**

Submissions

378. Submissions on the opening capital base for the third access arrangement period are addressed below under “Considerations of the Authority”.

112 Revised access arrangement information, Section 10.2.3, Tables 57 and 58.

113 Revised access arrangement information, Section 10.2.4, Tables 61 and 62.

Considerations of the Authority

379. The Authority considered whether Western Power's calculation of the capital base for each of the transmission and distribution networks is consistent with the requirements of the Access Code. These considerations are documented below under headings of:

- the general method applied in calculating the capital base;
- verification that stated new facilities investment in the first access arrangement period occurred (or for 2011/12 is reasonably forecast to occur); and
- determination of the capital base at the commencement of the third access arrangement period, taking into account:
  - an assessment of actual capital expenditure in the second access arrangement period against the test of section 6.51A of the Access Code;
  - depreciation;
  - redundant assets;
  - Western Power's proposed mid-year timing assumption; and
  - investment from prior periods.

General Method

380. Western Power has calculated the capital base for each of the transmission and distribution networks using a roll-forward method, applied in a manner consistent with the method contemplated in the note to section 6.48 of the Access Code.

381. The roll-forward method has been favoured by utility regulators throughout Australia and is the method mandated for electricity transmission and distribution networks of the NEM under Chapters 6A and 6 of the NER.

382. The Authority is satisfied that the method used by Western Power is consistent with the Code objective.

Verification of Capital Expenditure in the Second Access Arrangement Period

383. In accordance with the Authority's Guidelines for Access Arrangement Information, Western Power has provided regulatory accounts that reconcile costs of regulated activities with a set of base accounts for the business. These regulatory accounts provide a reconciliation of claimed new facilities investment with actual capital costs incurred in 2009/10 and 2010/11 as indicated in Table 40.

Table 40 Reconciliation of claimed new facilities investment for 2009/10 and 2010/11 with recorded capital costs for the Western Power business ($ million at 30 June 2012)

Network and Year	Base Account	Adjustments	Regulatory Account	Claimed new facilities investment
Transmission 2009/10:				
Capital expenditure	250.4	11.1	261.5	261.5
Contributions	(13.3)	(22.6)	(35.9)	(35.9)
Net expenditure	237.1	(11.5)	225.6	225.6
Transmission 2010/11				
Capital expenditure	188.4	(16.9)	171.5	169.4
Contributions	(47.0)	25.3	(21.7)	(21.7)
Net expenditure	141.4	8.4	149.8	147.6
Distribution 2009/10				
Capital expenditure	520.6	(1.1)	519.5	519.5
Contributions	(94.6)	13.9	(80.7)	(80.7)
Net expenditure	426.0	12.8	438.8	438.8
Distribution 2010/11				
Capital expenditure	531.6	1.4	533.0	533.0
Contributions	(92.2)	1.1	(91.1)	(91.1)
Net expenditure	439.4	2.5	441.9	441.8

384. The Authority notes that Western Power has excluded $2.1 million transmission expenditure in 2010/11 from its new facilities investment claim as it relates to expenditure on the connection for the Binningup Desalination Plant which the Authority assessed as not meeting the new facilities investment test in its decision published on 2 March 2011.[114]

385. The adjustments made in the regulatory accounts to capital expenditures for transmission include:

- removal of capitalised borrowing costs that are not properly recorded as capital expenditure in the regulatory accounts;
- restating capital contributions to be on a cash received basis;
- reversal of a write down in the statutory accounts for cancelled/deferred projects; and
- inventory adjustments.

386. The Authority observes that the regulatory accounts presented by Western Power were audited for Western Power by the Office of the Auditor General. The Authority has had the regulatory accounts reviewed by BDO.

387. The Authority has considered the adjustments made in the regulatory accounts and, whilst it agrees that the first two adjustments noted above (to remove capitalised borrowing costs and state capital contributions on a cash basis) are appropriate and in line with previous practice, the adjustments in relation to cancelled projects and inventory should not have been made.

114 2 March 2011, Economic Regulation Authority, *New Facilities Investment Test Binningup Desalination Final Decision* .

388. The 2010/11 regulatory accounts includes an increase to capital expenditure of $14.5 million which is described as being to reverse the 2010/11 statutory write down for cancelled/deferred capital projects as the capital expenditure qualifies for recognition in the regulatory asset base. The Authority does not consider expenditure which relates to cancelled or deferred projects meets the requirements of the new facilities investment test. If such expenditure has been identified for write-down in the statutory accounts, then it should not be added to the capital base.

389. The 2009/10 regulatory accounts included an increase to capital expenditure of $20.896 million which is described as being for year-end statutory inventory adjustments. The adjustment was subsequently reversed in the 2010/11 accounts as Western Power decided it did not wish to proceed with such an adjustment. Whilst the net effect for the 2009/10 and 2010/11 years in nominal terms is neutral, the Authority considers the figures should be restated correctly for each year for the purposes of establishing the opening capital base to ensure balances are stated correctly in real price terms.

390. The Authority requires capital expenditure for the 2009/10 and 2010/11 year to exclude expenditure relating to cancelled or deferred projects and for each year to be restated correctly to remove the statutory inventory adjustment made in the regulatory accounts.

Required Amendment 7

The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to cancelled or deferred projects and to reverse the statutory inventory adjustments in both years.

Capital Base at the Commencement of the Third Access Arrangement Period

Capital Expenditure during the second access arrangement period

391. A comparison of forecast and actual capital expenditure (net of capital contributions and gifted assets) over the first and second access arrangement periods is shown in Figure 5 and Figure 6 below.

Figure 5 Transmission network capital expenditure (real $ million at 30 June 2012)

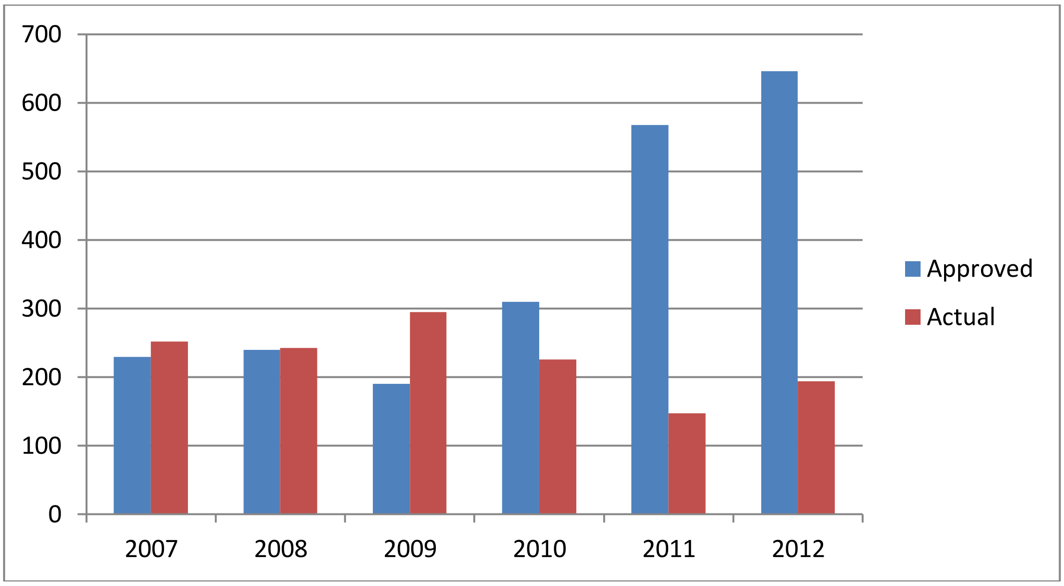
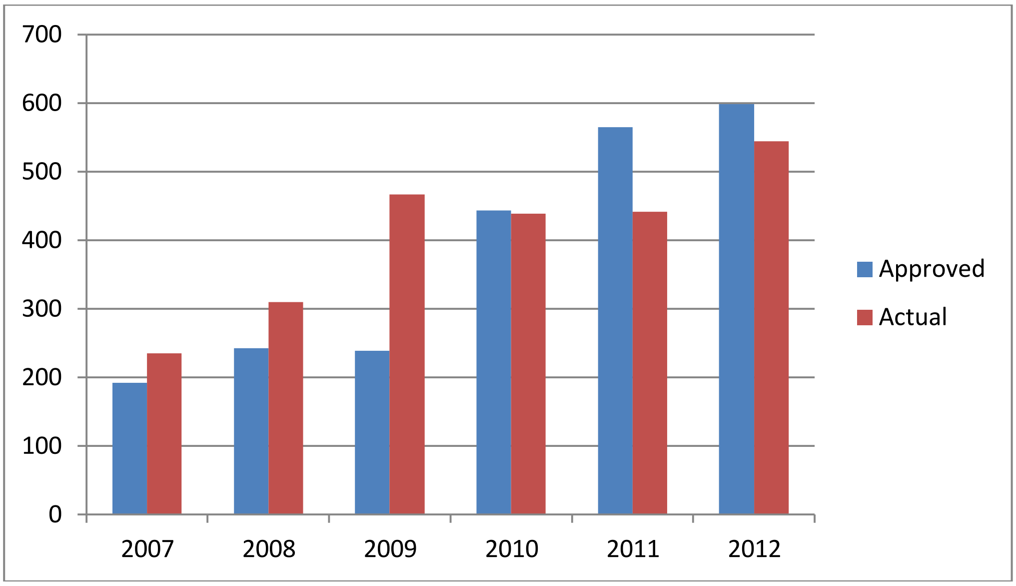


Figure 6 Distribution network capital expenditure (real $ million at 30 June 2012)



392. As can be seen in the figures above, Western Power has spent significantly below the amount forecast for the second access arrangement period. Based on the expenditure included in Western Power's proposed revised access arrangement submitted to the Authority on 30 September 2011, transmission expenditure is $957 million ($ real 30 June 2012) or 63 per cent below the forecast and distribution expenditure is $180 million ($ real 30 June 2012) or 11 per cent below the forecast.

393. The latest forecast provided by Western Power for the 2011/12 year, the final year of the current access arrangement period, indicates the under spend is likely to increase by a further $54 million. To the extent that the underspend relates to investment subject to the Investment Adjustment Mechanism, an adjustment is made to target revenue for the third access arrangement period to adjust for any under or over spend. This is discussed further in paragraphs 981 to 985.

394. The Authority's technical consultant has reviewed the actual level of capital expenditure for the second access arrangement period against the amounts forecast at the second access arrangement review. GBA notes that:[115]

> The main reason cited by Western Power for the lower level of capital expenditure in the AA2 period is the impact of the global financial crisis (GFC), although it also indicated that deliverability was an issue in some areas. Western Power indicated that the GFC affected the availability of funding and its budget allocation from the Government was less than the AA2 capital expenditure approved by the Authority. Given this, Western Power had to request additional funding from the Department of Treasury. The uncertainty around the availability of funds, together with the write-down in the value of the capital base as a result of the Authority's AA2 final decision, led Western Power to review its capital works plan and a number of projects were put on hold pending the outcome of this review. Following the review a number of projects have been deferred or cancelled.
>
> Another reason given by Western Power for the reduced AA2 capital expenditure was favourable weather conditions, which presumably led to lower levels of remedial work due to a reduction in asset failures and outages.

395. To assist the Authority to understand the reasons for the underspend over the second access arrangement period, GBA compared the actual and forecast capital expenditure for the second access arrangement period by asset category. For the transmission service, GBA identified that capacity expansion, customer driven and generation driven projects had the biggest under expenditure with these categories accounting for slightly over 90 per cent, or nearly $900 million of the total underspend.

396. Underspend on customer driven projects amounts to 29 per cent of the total capital expenditure approved for the second access arrangement period or 64 per cent of Western Power's total transmission related capital expenditure underspend. This was due to lower than expected demand for connection to the network and also to the impact of process and cost efficiencies achieved by Western Power. GBA acknowledges that customer driven capital expenditure is difficult to forecast as Western Power must react to customer applications. Its ability to forecast customer requirements in advance is limited.

397. GBA obtained a table from Western Power which provides further detail of the underspend relating to capacity expansion expenditure.[116] The largest underspend ($259 million) related to the Mid West Energy Project, the majority of which has been deferred until the third access arrangement period. A further $241 million has been "deferred indefinitely", $211 million has been deferred due to a "review of transmission planning approach and processes" and $156 million is described as being "deferred".

398. GBA considered the extent to which demand growth below the level anticipated at the time of the second access arrangement review may explain the level of underspend. However, its analysis of the actual maximum demand compared with the forecast maximum demand showed that actual demand for 2011 was actually higher than the forecast which suggests that the significant reduction in transmission capacity expansion capital expenditure has been achieved in spite of an actual demand

[115] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 46-47.

[116] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017,* Table 5.1, p. 48.

comparable to, or even higher than, the forecast at the time of the second access arrangement review.

399. In relation to the distribution service, GBA identified that the expenditure categories with the most significant underspend were capacity expansion, safety and reliability.

400. The largest underspend in distribution capacity expansion related to high voltage distribution network projects being deferred or cancelled due to improved investment decision processes. Western Power also indicated that, as a result of improvements in processes relating to distribution planning, investment decision making and documentation requirements, a number of planned capacity expansion projects have been deferred or cancelled. An amount of $29 million on the Perth CBD duct and pit systems was deferred as a result of funding constraints and subsequent reprioritisation of the works program.

401. The most material expenditure areas having an impact on the underspend for safety, environment and statutory expenditure relate to bushfire management and power quality compliance. GBA advised that Western Power provided numerous reasons for the expenditure variances, including operational efficiency improvements and reducing labour costs from bundling work across programs by geographic region.

402. For reliability driven expenditure, which was $57 million below forecast, GBA advise that Western Power stated that funding reliability projects became less critical as they were meeting and maintaining service standard benchmarks so expenditure was transferred to more critical work programs.

403. In contrast to network capital expenditure, actual expenditure for information technology and business support expenditure was $40 million higher than forecast with the largest overspend relating to information technology.

404. More than 50 per cent ($22.3 million) of this difference is due to the fact that IT infrastructure expenditure is now fully recovered from regulated revenues. Prior to 2010/11, Western Power shared its IT infrastructure with Synergy, Horizon Power and Verve Energy, which were disaggregated from Western Power in April 2006. Capital expenditure and operating expenditure relating to the disaggregated entities were recovered from these entities and those relating to Western Power were charged back to the regulated business through business unit charges. Western Power's sourcing model changed in 2010/11 and it no longer holds capital assets to provide IT infrastructure to the disaggregated entities.

405. GBA's overall conclusion in relation to the comparison of actual capital expenditure during the second access arrangement period with the forecast was:[117]

> Western Power's total capex during AA2 is expected to be 34% ($1.3 billion) lower than the $3.9 billion approved by the Authority. The major areas of under-expenditure were network related, particularly capacity expansion and customer driven capex, on transmission and, to a lesser extent, distribution assets. However, non network IT capex was overspent.
>
> Most of the under-expenditure was in the capacity expansion and customer driven capex categories. The funding allocated in the AA2 access arrangement to finance the under-expenditure in these categories will be returned to customers during AA3 through

117 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 52-53.

the IAM. However the IAM does not apply to non-growth driven capex and the funding provision for non-growth driven capex that was not utilised in AA2 will be retained by Western Power and not returned to customers.

Customer driven capex was significantly lower than the level forecast at the time of AA2 approval, indicating a reduced demand for network connection, particularly from larger customers. This capex is difficult to forecast.

Western Power further suggested that the GFC reduced the demand for electricity and much of the approved AA2 capex was therefore not necessary. However, our analysis indicates that the peak demand in 2010-11, the most recent year for which an actual peak demand is available, was comparable to that anticipated at the time the Authority issued its final decision on the AA2 access arrangement.

A major reason for the under-expenditure was that the Authority's AA2 final decision did not allow all Western Power's actual AA1 capex to be included in the opening capital base for AA2. As a result, Western Power put much of its planned capacity expansion expenditure on hold while it reviewed its network development planning processes. Subsequently, many planned projects have been deferred or cancelled. A further factor impacting the actual capex during AA2 has been funding constraints imposed by the Government. Western Power finances its capital works program from funding provided by the Western Australian Treasury, which we understand has required all state owned entities to restrain their capex programs as a response to the GFC. Western Power has not been immune to these pressures.

Notwithstanding this significant capex underspend, Western Power has met or exceeded 34 of the 38 (89%) AA2 access arrangement network service level benchmarks over the first two years of AA2. Hence, the capex under expenditure has not caused Western Power's service levels, on average, to fall below the service levels forecast at the time of AA2 approval. In fact the actual service levels have been significantly better than anticipated, since we understand that the AA2 service level benchmarks were set at a level where it was thought that there was only a 50% probability of each benchmark being exceeded.

We conclude that there was a significant level of inefficiency in Western Power's AA2 capex forecast, which was higher than it should have been. While Western Power's capex management, project forecasting and estimating processes have now improved, the Authority may wish to take a conservative approach in approving the AA3 capex. The Authority could decide that, given that any capacity expansion capex overspend that meets NFIT requirements can be recovered in AA4 through the investment adjustment mechanism, it is better for the approved capex to be a little lower, rather than substantially higher, than the amount eventually required. Customers will then not be asked to pay more during AA3 than needed to fund the actual capex requirement, and the incentive on Western Power to deliver only an efficient level of capex is likely to be greater. This is because the actual AA3 capex is likely to be subject to more intense ex-post scrutiny at the time of the AA4 review if it is higher than the Authority's approved amount.

Application of the New Facilities Investment Test to Actual Capital Expenditure

406. In order to include the actual (and estimated actual for 2011/12) capital expenditure incurred during the second access arrangement period in the capital base, Western Power must satisfy the Authority that the expenditure meets the new facilities investment test under section 6.52 of the Access Code.

407. As can be seen in the discussion above, Western Power has included the entire capital expenditure incurred in 2009/10 and 2010/11, apart from $2.1 million relating to Binningup Desalination Plant, in its calculation of the opening capital base for the

third access arrangement period. It has also included its total forecast capital expenditure for 2011/12 in the capital base.

408. The new facilities investment test of section 6.52 of the Access Code comprises two parts.

409. The first part of the new facilities investment test under section 6.52(a) of the Access Code is a test of whether the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, taking into account whether the new facility exhibits economies of scale or scope, the increments in which new capacity can be added and long term forecasts of sales of services. This is hereafter referred to as the "efficiency test".

410. The second part of the new facilities investment test under section 6.52(b) of the Access Code is a test of whether the new facilities investment provides benefits that justify addition of the new facilities investment to the capital base of the covered network and the recovery of the cost of the investment from users of the network generally. Three limbs of the second part of the new facilities investment test provide for new facilities investment to be added to the capital base if one or more limb is satisfied:

- the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment (the "incremental revenue test"); or
- the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs (the "net benefits test"); or
- the new facility is necessary to maintain the safety and reliability of the covered network or its ability to provide contracted covered services (the "safety and reliability test").

411. The purpose of the second part of the new facilities investment test is to enable market forces to discipline investment in the network and to ensure that investment only occurs where there is a net economic benefit. The manner in which this is achieved is to allow new facilities investment to be added to the capital base where the benefits are such that those who generate, transport and/or consume electricity in the SWIS (as a group) are better off (or at least no worse off) in economic terms than they would be if the investment did not occur. The benefits to existing users may be in the form of:

- economies of scale in the network, which is the subject of the incremental revenue test under section 6.52(b)(i)A of the Access Code;
- broad benefits through better functioning of the covered network or electricity system as a whole, which is the subject of the net benefits test under section 6.52(b)(ii) of the Access Code; and
- the maintenance of safety and reliability of the network, which is the subject of the safety and reliability test under section 6.52(b)(iii) of the Access Code.

412. In the event that the benefits to existing users are less than the value of new facilities investment, the residual amount (that would not satisfy the new facilities investment test) would need to be financed by some other means. This would typically be a capital contribution from the user of the network or end customer of electricity whose service application gives rise to the need for the investment. The requirement for the new user to pay a contribution should, in principle, engender efficient investment, as

the new user would only pay a contribution where the benefits to the user exceed the value of the contribution.

413. The Authority's technical adviser undertook a review to assess whether actual and forecast expenditure for the second access arrangement period meets the new facilities investment test. This was done by reviewing a sample of 19 capital projects undertaken during the second access arrangement period to assess whether these individually met the new facility investment test requirements. The review included an assessment of:

- the extent to which Western Power applied its expenditure management governance processes in the development, approval and implementation of the project or program;
- the justification for any positive or negative variance between the estimated cost at the time of project of program approval and the final project or program cost;
- the justification for project or program implementation schedule changes; and
- the scope of the forecast project compared to the scope at the time of project approval.

414. GBA's approach was predicated on the assumption that if a capital expenditure project or program was implemented in accordance with Western Power's expenditure governance procedures then, assuming these procedures were consistent with good industry practice, it can be assumed that implementation was efficient and wasteful expenditure did not occur.

415. GBA also considered the extent to which the project satisfied the second limb of the new facilities investment test. This excluded an examination of the basis on which this limb was satisfied and whether this assessment was made at the time the project was approved in a manner that is consistent with Western Power's governance procedures.

416. Since submitting the proposed revised access arrangement on 30 September, Western Power has updated its forecast expenditure for the 2011/12 year. GBA's review was based on this updated forecast. GBA notes that its review indicated that Western Power is still uncertain of the status of some of the 2011/12 forecast capital expenditure. The Authority expects that Western Power will include an updated forecast for the 2011/12 year as part of its response to the draft decision.

417. The results of GBA's review are detailed in Appendix A of its report and summarised in sections 5.3.2.1 to 5.3.3.

418. GBA noted that the documentation provided by Western Power for each individual project or program review varied in the level of detail and the quality and quantity of information provided which made it difficult in some cases to assess the level of rigour applied by Western Power in developing the scope of the projects or programs and the priority given to developing and evaluating different project alternatives.

419. Apart from reservations about the extent to which different alternatives were developed and evaluated in the project development phase, GBA considered that the implementation of Western Power's expenditure governance processes during the second access arrangement period were generally good and that the management of capital expenditure had improved as a result.

420. However, in its review of specific projects, GBA identified a number of expenditure items which do not meet the new facilities investment test. These comprise:[118]

- $5.7 million in relation to a cost overrun on phase 1 of the Mobile Work Solution project which forms part of the Strategic Program of Works;
- $102,000 incurred on planning for a second Picton-Busselton 132 kV Line which has been deferred indefinitely;
- $4.5 million in relation to planning and environmental costs which are not directly related to a specific project or program and GBA considers do not meet the requirements of the new facilities investment test; and
- $1.9 million in relation to transmission line relocations which Western Power intends to recover in full from the customers concerned.

421. GBA was unable to form a view on $9 million in relation to a cost overrun on elements of the Strategic Program of Works because the information provided by Western Power indicated problems with elements of the project's business case.

422. The Authority has reviewed the advice from GBA and considers that the expenditure identified in paragraph 420 and 421 above, which totals $21.2 million, does not meet the requirements of the new facilities investment test and therefore should not be included in the opening capital base for the third access arrangement period. The Authority has estimated that $12 million of the adjustment relates to transmission and $9.2 million relates to distribution and for modelling simplicity has assumed the adjustments apply evenly over the second access arrangement period.

423. The Authority will, accordingly, require that the amount of new facilities investment for the second access arrangement period that is to be added to the capital base should be reduced to exclude investment to the value of $21.2 million. The amended values of new facilities investment are shown in Table 41.

118 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 59-60.

Table 41 Amounts of new facilities investment in the second access arrangement period to be added to the capital base (real $ million at 30 June 2012)[119]

	2009/10	2010/11	2011/12
Transmission			
Total new facilities investment claimed by Western Power	225.6	147.6	193.8
Reversal of regulatory accounting adjustments	(23.2)	7.9	
Revised forecast for 2011/12			(50.5)
Expenditure which does not meet new facilities investment test (paragraph 423)	(4.0)	(4.0)	(4.0)
Adjustment for the Mid West Energy Project			6.9
Value to be added to the capital base	198.3	151.6	146.1
Distribution			
Total new facilities investment claimed by Western Power	438.8	441.8	544.5
Reversal of regulatory accounting adjustments	0.9	(1.2)	
Revised forecast for 2011/12			(3.8)
Expenditure which does not meet new facilities investment test (paragraph 423)	(3.1)	(3.1)	(3.1)
Value to be added to the capital base	436.6	437.5	537.6

Required Amendment 8

The proposed revised access arrangement should be amended to reflect the values shown in Table 41 above.

Inventory

424. Western Power proposes including an amount relating to inventory assets in the opening capital base for the third access arrangement period which it states is to "recover the financing costs associated with efficiently holding these assets for users of covered services".

425. Western Power provided information in Appendix D of its proposed revised access arrangement information in relation to how it has determined the level of inventory and comparisons with other service providers which it considers demonstrates that its proposed amount falls within the range of values in other states.

426. Whilst the Authority acknowledges there may be a working capital requirement in relation to the need to hold inventory, it considers Western Power's proposal to add inventory to the capital base is overly complex and lacks transparency. Western Power suggests that its proposed approach is consistent with the practice of other electricity network businesses and refers to the published Cost Allocation Methods

119 Expenditure on Strategic Program of Works projects which does not meet the new facilities investment test is allocated based on the ratio of Western Power's proposed allocation of IT expenditure to transmission and distribution in each year of the regulatory period.

(CAM) for a number of companies.[120] However, the Authority has been unable to establish that these companies include inventory costs in their capital values and considers the CAM is more likely to be describing how the cost of materials taken from inventory is allocated (i.e. once such materials form part of capital or operating expenditure).

427. The Authority has given further consideration to the requirement for a return on working capital in relation to inventory in paragraphs 926 to 930.

Required Amendment 9

Western Power's proposed adjustment to include the cost of inventory in the capital base must be removed.

Asset Disposals

428. During the second access arrangement review, the Authority determined that the value of any revenues from disposal of assets in the first access arrangement period should be added to the value of redundant assets applied in the calculation of the capital base at the commencement of the second access arrangement period.

429. Western Power has followed this process in its calculation of the opening capital base for the third access arrangement period by deducting asset disposals based on the gross asset sales proceeds.

Depreciation

430. A note to section 6.48 of the Access Code contemplates a roll forward calculation of the capital base involving a deduction of an amount of depreciation.

431. In calculating its proposed value of the capital base at the commencement of the third access arrangement period, Western Power has applied values of depreciation taken into account in determining notional capital base values and the target revenue for the second access arrangement period, escalated for inflation to dollar values at 30 June 2012. The Authority is satisfied that this approach is consistent with applying the roll-forward calculation in a manner consistent with the Code objective.

432. Western Power has also proposed including accelerated depreciation in relation to distribution assets that were decommissioned due to the State Underground Power Program. This is consistent with the forecast assumptions for the second access arrangement period.

433. The Authority's technical adviser has noted that Western Power has not included accelerated depreciation in relation to wooden poles or meters that are replaced. Whilst many of these assets will have reached the end of their useful life and already be fully depreciated, GBA considers there will be instances of some such assets not being fully depreciated. The consequence of this is that the cost of those assets will continue to be recovered over the notional life of the asset, and therefore included in

[120] Western Power Access Arrangement Information Appendix D, p. 1.

future charges, rather than being written off immediately and included in current charges.

434. The Authority requires Western Power to establish the value of any redundant assets included in its current asset base and to include accelerated depreciation to fully write them off.

Required Amendment 10

Western Power must establish the value of any redundant assets included in its current asset base and to include accelerated depreciation to fully write them off.

Mid-Year Timing Assumption

435. Western Power has proposed to adopt a mid-year timing assumption for capital expenditure to establish the opening capital base for the third access arrangement period. Western Power states that the 'mid-year timing is appropriate to simulate the impact of incurring new facilities investment throughout the year'.[121] It also notes the timing of its "summer ready" program requires a significant portion of its investment program to be completed by December each year.

436. Western Power states that, to be consistent with the target revenue end-of-year cash flow timing assumption, capital expenditure added to the capital base effectively on a mid-year basis must be adjusted to an end-of-year cash flow. It notes this has the effect of capitalising the first six months of costs and provides for them to be recovered over the life of the assets. It has achieved this by adjusting the new facilities investment in each year for the time value of money for six months by applying the following factor to new facilities investment and adding this amount to the capital base. Western Power notes that its proposed revision is in line with the approach currently used by the AER in its 'Post Tax Revenue Model' (**PTRM**).

437. A number of submissions[122] from interested parties had significant concerns with this proposed amendment noting that it would result in higher charges for customers and had no justification.

438. The change in timing assumption proposed by Western Power is a departure from the approach proposed by Western Power and approved by the Authority in the past two access arrangement review periods, which assumed end-of-year timing for capital and operating expenditure incurred and revenue collected. A change in timing assumption for capital expenditure incurred mid-year would result in an uplift in target revenue (target revenue would be maintained at a higher level due to the return on asset and depreciation being calculated on a higher regulatory asset value).

439. Western Power's modelling approach would not recognise the benefits to Western Power receiving revenue throughout the year. If this was to be recognised then this would have the effect of decreasing target revenue because Western Power receives

---

121 Revised Access Arrangement Information, Section 10.2.6, p. 243.

122 Landfill Gas and Power, WALGA and WAMEU.

a time value of money benefit for receiving revenue throughout the year rather than all of the revenue at the end of the year.

440. The end-of-year cash flow modelling is preferred by the Authority for its transparency and simplicity of use, not that it reflects the actual cash flows of Western Power's business. The more precise but significantly complex alternative would be to model all cash flows throughout the year. While not proposing this, Western Power is proposing to adopt an approach that has an inconsistent treatment of all cash flows.

441. Western Power's proposed mid-year capital expenditure timing does not also account for the fact that assets will be retired from the capital base throughout the year. As assets are understood to enter the capital base throughout the year it seems reasonable that assets would also become obsolete or disposed of throughout the year. As a result, the return on the capital base would be higher than should otherwise be as the capital base is not written down on a mid-year basis.

AER Approach

442. As noted above, Western Power's proposed revision is similar to the approach currently taken by the AER. However, it should be noted that the AER has previously raised concerns with its PTRM.

443. The PTRM was originally developed by the ACCC for transmission networks. When responsibility for regulating distribution networks moved from the state regulators to the AER, the AER was required to develop guidelines, including a revenue model. The AER used the transmission PTRM as a starting point and carried out a consultation in 2007.

444. In its Issues Paper[123], the AER noted that the adoption of a model which assumed operating expenditure and revenue on an end-of-year basis and capital expenditure on a mid-year basis is not 'internally consistent'. The AER noted that improvements to the transmission PTRM could be made through present value adjustments to operating expenditure and revenue. However, the AER noted that this would only reduce 'material over-compensation of revenue requirements' provided by the transmission PTRM which may result in certain circumstances.

Conclusion

445. Although Western Power points to the approach adopted by the AER to support its proposed revision, it does not mention other differences in relation to cash-flow modelling assumptions between Western Power's approach and the AER. Most significantly, the AER does not include an allowance for return on working capital. Historically Western Power has done so and is not proposing that it be removed or adjusted as a result of its proposed changes to modelling capital expenditure.

446. Western Power is selective in its proposed modelling changes as it is not proposing that the Authority should account for revenue collection on a mid-year basis. The same arguments Western Power has raised in relation to capital expenditure could also be made in relation to revenue recognition as it is also received throughout the year. The proposed change by Western Power does not also reflect that capital expenditure would also be retired throughout the year as well. Western Power has

123 AER, Issues Paper Guidelines, models and schemes for electricity distribution network service providers November 2007.

'cherry-picked' the modelling change which will result in it receiving a benefit at the expense of customers.

447. Western Power's proposed mid-year capital expenditure timing adds further complexity to the financial modelling and is not consistent with the modelling of other cash flows as noted above. As a result, the Authority does not approve Western Power's proposal to adjust capital expenditure timing to mid-year.

Required Amendment 11

The proposed revised access arrangement must be amended such that the 'time value of money adjustment' for mid-year capital expenditure timing is removed from the rolled forward capital base and notional capital base for AA3.

Investment from Prior Periods

Western Power's Claim

448. Western Power has proposed to add $244.43 million ($ real as at 30 June 2012) of the disallowed capital expenditure incurred during the first access arrangement to the opening capital base for the third access arrangement period. It describes this expenditure as "speculative investment".

449. Western Power notes that its opening capital base at 1 July 2010 reflected a lower level of new facilities investment than actually occurred in the first access arrangement period as the capital base was reduced by $261.09 million ($ real as at 30 June 2009).

450. In its proposed revised access arrangement information for the third access arrangement period, Western Power notes that part of the $261.09 million related to specific projects which it accepts did not, and continue not, to pass the new facilities investment test and should not be added to the capital base. These projects amount to $37.72 million and include:

- $18.4 million ($ real as at 30 June 2009) of inefficiencies associated with inadequate cost estimation across a number of specifically identified projects;
- $9.2 million ($ real as at 30 June 2009) identified overcharging by contractors on a number of reviewed arrangements;
- $3.15 million ($ real as at 30 June 2009) which is a portion of the cost of the 490 MVA Wells terminal station transformer to connect the Boddington Gold Mine; and
- $6.97 million ($ real as at 30 June 2009) relating to the Busselton to Margaret River transmission line project.

451. Western Power describes the remaining $223.4 million ($ real as at 30 June 2009) of investment incurred in the first access arrangement period as having been disallowed on the basis of the extrapolation of specific findings to the whole investment. Western Power states that it has adopted a similar approach to the speculative investment amount:

> "Our review of certain projects and programs has identified documentation that demonstrates that NFIT is satisfied for those projects and programs. Using a similar approach to that adopted by the Authority, we extrapolate those findings to establish that the full amount of disallowed expenditure that does not relate to the above mentioned identified projects satisfies NFIT."

452. Western Power has then adjusted these values to "account for the time value of money and equivalent, in net present value terms" to June 2012 values. The total value it claims should be added to the opening capital base for the third access arrangement period is $244.4 million ($ real as at 30 June 2012). This is shown in Table 42 below.

Table 42 Western Power's proposed investment from prior periods to be added to the opening capital base for the third access arrangement period

	2006/07	2007/08	2008/09	AA1 Total
$ million real at 30 June 2009				
Distribution speculative investment that satisfies NFIT	27.8	28.8	32.4	134.4
Transmission speculative investment that satisfies NFIT	37.1	42.2	55.1	89.0
Total speculative investment that satisfies NFIT	64.9	71.0	87.5	223.4
$ million real at 30 June 2012				
Distribution speculative investment that satisfies NFIT	40.6	46.2	60.2	147.1
Transmission speculative investment that satisfies NFIT	30.4	31.5	35.5	97.4
Total to be added to the capital base	71.0	77.7	95.7	244.4

453. In its proposed revised access arrangement information, Western Power notes that it has comprehensively reviewed its governance and capital planning approach:

> "A particular area of focus has been the documentation that we use to demonstrate compliance with NFIT. This followed a number of observations and comments made by SKM that there was room for improvement in our documentation[124]. These comments formed the basis for the Authority's decision in relation to the level of inefficiency associated with our AA1 capital expenditure and we have sought to constructively respond to these matters.
>
> We examined in detail the documentation supporting the highest valued new facilities investment projects and programs to be undertaken in AA2. This review identified opportunities to improve how our project and program documentation demonstrates that the NFIT is satisfied. Importantly, however, the review did not identify any systemic issues associated with option choice and investment timing."[125]

124 P61, Western Power's second submission to the Economic Regulation Authority's Draft Decision on the proposed revisions to the access arrangement for the SWIN, Attachment F2- Opinion by Sinclair Knight Mertz, 10 September 2009.

125 Western Power, Access Arrangement Information, Appendix C - AA1 Speculative Investment, p. 4.

454. Western Power states that its review of governance and planning processes included information relevant to the new facilities investment during the first access arrangement period because six of the specific projects reviewed included expenditure in the first access arrangement period and a number of the programs reviewed related to recurring programs of work (including pole management, bushfire management and reliability improvements) which also occurred during the first access arrangement period.

455. In Appendix C, Western Power has provided a list of the projects and programs it has reviewed and the total expenditure for each expressed in real dollars at 30 June 2012:

- Distribution pole replacement ($104.4m)
- Distribution improvement in service-reliability driven ($56.9m)
- Bushfire management ($38.2m)
- Low Value Asset Pool meters ($34.6m)
- Neerabup- new terminal station ($51.8m)
- Alinta cogen Southern Terminal ($32.7m)
- Overhead Customer Service Connections ($42.2m)

456. Western Power provided confidentially the documentation for two of these projects (Bushfire Management Plan and Overhead Customer Service Connections), and indicated the rest could be made available if required. Western Power considers that, given the representative nature of the projects reviewed, and that no systemic failures were identified, it is reasonable to assume that the whole of the disallowed expenditure satisfies NFIT.

Submissions

457. Griffin considers that the investment from prior periods which did not meet the new facilities investment test should not be added to the regulated capital base.[126]

458. Landfill Gas and Power sees NFIT as the appropriate mechanism and believes if the investment meets NFIT it should be included in the capital base.[127]

459. ERM Power believes there is not enough information provided to justify the inclusion of the $244.4m in the opening capital base, and requests that ERA determine whether Western Power's evidence is compelling enough to reverse the previous decision where NFIT was not satisfied.[128]

460. Verve Energy considers that previously rejected expenditure should be subject to the ERA's careful scrutiny as to its being re-evaluated against NFIT.[129]

---

126 November 2011, Griffin Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

127 December 2011, Landfill Gas and Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

128 December 2011, ERM Power Ltd, *Submission to the Economic Regulation Authority on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network.*

129 December 2011, Verve Energy, *Public Submission on the Call for Submission on Western Power's Proposed revisions to the Access Arrangement for the Western Power Network (AA3).*

461. The Office of Energy's submission noted the following:[130]

> Given the general reasons for the initial disallowance, the Office supports the view that new information presented by Western Power in its third access arrangement proposal in relation to past new facility investment warrants thorough consideration by the Authority. The Office is of the view that Western Power has made some assumptions in relation to the value of the amount to be rolled into the capital base, based on extrapolated findings which the Authority should assess in greater detail.
>
> The Office supports the notion of assessment of speculative investment under the Access Code as such an assessment aligns itself with the notion of the ex-post assessment of investment by the Authority. The Office is of the view that the roll in of lost capital expenditure that can be shown to meet the speculative investment provisions will promote the efficiency of the business if the assessment is conducted in a transparent and consistent manner.
>
> It is noted that the Access Code provides little guidance as to the management and governance of the Speculative Investment Fund and the Office makes itself available to the Authority to assist with consideration of this previously unused provision.

462. In its submission to the public consultation, Western Power considers that the statement in the Authority's Issues Paper (*"Western Power has proposed to include $244.4 million (real dollars at 30 June 2012) in the opening capital base for AA3 capital expenditure in AA1 that did not meet the requirement of the new facilities investment test*") is incomplete. Western Power considers it should be noted that this expenditure is speculative investment. Western Power claims that a review of documentation relating to specific projects and programs undertaken during the first access arrangement period has shown that these investments satisfied the NFIT and can be added to the capital base.

463. The Authority notes Western Power's claim that the expenditure is "speculative investment." Western Power does not directly discuss the basis for this view but has included an extract of sections 6.58 to 6.60 of the Access Code in its proposed revised access arrangement information.[131]

464. It would appear Western Power has applied a literal interpretation of section 6.58 such that any expenditure that does not meet the new facilities investment test must therefore be "speculative investment".

465. "Speculative Investment" is defined in the Code as being, for a "new facility", the amount determined under section 6.58 of the Access Code. "New facility" is defined in the Code as any capital asset developed, constructed or acquired to enable the service provider to provide covered services including assets required for the purpose of facilitating competition in retail markets for electricity.

466. Section 6.58 of the Access Code provides that the "speculative investment amount" (if any) for a new facility at any time is equal to:

a) The "new facilities investment" (i.e. capital costs incurred by Western Power in developing, constructing and acquiring the "new facility");

[130] December 2011. Office of Energy, *Public Submission on the Issues Paper on Western Power's Proposed Amendments to its Access Arrangement for the Third Regulatory Period.*

[131] Western Power Access Arrangement Information, Appendix C - AA1 Speculative Investment, p. 2.

b) Minus any amount that has already been added to the capital base under section 6.57;

c) Minus any amount for which a contribution has been provided by a user to the service provider;

d) Minus any part of the speculative investment amount previously added to the capital base at a later time under section 6.60.

467. Section 6.60 provides that if a "speculative investment amount" was created for a new facility and a determination of the capital base is made under s6.44 at a later time, then any part of the speculative investment amount which satisfies the NFIT at the later time may be added to the capital base.

468. The Authority is concerned that Western Power's interpretation of section 6.58 may not have been the intention of the drafters of the Access Code, particularly, when read in conjunction with section 6.60(a) which applies where "a *speculative investment amount* was *created* for a *new facility*" (emphasis added). Put another way, the Authority is of the view that any speculative investment for the purpose of s 6.58 and 6.60 of the Access Code should have been specifically identified as such at the time when the Authority determined whether the NFIT is satisfied. The Authority is concerned that Western Power's construction of section 6.58 effectively enables a service provider to re-open a properly made decision of the Authority under a previous AA review.

469. Notwithstanding the above, the Authority agrees there is a lack of clarity in the wording of the Access Code. The Authority has reviewed Western Power's proposal for compliance with the NFIT as set out below.

470. The amount excluded by the Authority comprised:

- An amount of $23.24 million (in dollar values of 30 June 2009) in respect of transmission projects that have been delayed or not proceeded, or amounts that should have been recovered through capital contributions:
  - $6.969 million (in dollar values of 30 June 2009) Busselton-Margaret River line project which did not proceed;
  - $3.151 million (in dollar values of 30 June 2009) amount not recovered from customer in relation to the 490MVA transformers at Wells Terminal;
  - $9.9 million (in dollar values of 30 June 2009) in relation to the North Country Region 330kV transmission project;
  - $3.25 million (in dollar values of 30 June 2009) for contribution in relation to the connection of the Newgen Neerabup Power Station which Western Power had failed to properly account for.
- An amount of $126.87 million (in dollar values of 30 June 2009) in respect of inefficiencies arising from deficiencies in processes of cost estimation and from overcharging by contractors:
  - $117 million (in dollar values of 30 June 2009) relating to inefficiency arising from poor cost estimation processes (five per cent of $910 million (net of previous adjustment) of investment in the transmission network and $1,436 million distribution expenditure);

  – $9.56 million (in dollar values of 30 June 2009) inefficiency arising from overcharging by contractors.

- $110.97 million (in dollar values of 30 June 2009), being five per cent of capital expenditure net of the above adjustments and of gifted assets, reflecting the view of the Authority that inefficiencies had occurred in the selection and timing of augmentation projects as a result of deficiencies in methods for forecasting demand for network services and deficiencies in analysis of options for augmentation projects.

471. Each of these items is considered below.

Busselton-Margaret River Line Project

472. Western Power accepts that this expenditure should not be included in the regulatory capital base.

Transformers at Wells Terminal

473. Western Power accepts that this expenditure should not be included in the regulatory capital base.

North Country Region 330kV transmission project

474. In its final decision for the current access arrangement, the Authority disallowed $9.9 million ($ real as at 30 June 2009) relating to early planning and design costs for the north country region 330 kV transmission project. Western Power's third access arrangement period submission notes the expenditure was necessary to complete system modelling, options analysis, regulatory test preparation and design development.

475. The current access arrangement Final Decision notes (page 191) that Western Power considered that the expenditure satisfied clauses 6.52(a) and 6.52(b)(iii) of the Access Code and that the project had "passed" the regulatory test and been given the conditional "go-ahead" by the State Government, albeit with a modified scope. However, the Authority found:

> "Contrary to the submission from Western Power, other information available to the Authority indicates that it is uncertain whether the North Country Region 330kV transmission project will proceed as currently proposed and, if so, the timing of the project. In particular, advice from Western Power indicates that it is reviewing the project taking into account, inter alia, options for undertaking the project as a single stage or two stage project, revised forecasts of demand for network services, and interaction between the project and the proposed Eneabba to Karara transmission line project. For reason of the uncertainty with the project, the Authority considers that costs to date on this project should not be added to the capital base at this time."

476. Western Power's third access arrangement period submission (AAI Appendix C page 7) claims that the project is now proceeding and the uncertainty no longer exists. The Authority notes that the Final Decision on the New Facilities Investment Test Application for the Mid West Energy Project (Southern Section) was published by the Authority on 27 January 2012. The pre-approved expenditure included all planning and design costs in relation to the Mid West Energy Project (Southern Section) which the Authority determined to be efficient.

477. For the purposes of this draft decision, the Authority has adjusted Western Power's proposed capital expenditure in relation to the Mid West Energy Project (Southern

Section) to be consistent with the amount approved by it on 27 January 2012. The Authority does not consider any expenditure over and above the amount set out in that decision meets the new facilities investment test.

478. Any costs that relate to the section of line between Eneabba and Geraldton should not be added to the capital base at this time as there is no certainty at this stage that the northern section of the project will proceed. If the project were to proceed in the future, Western Power would need to provide sound evidence that any such costs were directly relevant to the final design of the project.

Newgen Neerabup Power Station

479. Western Power has not provided any evidence as part of its third access arrangement period proposal for why this should be included in its capital base. The Authority confirms its previous view that Western Power failed to account properly for a $3.25 million contribution in relation to the connection of the Newgen Neerabup Power Station and that it should be excluded from the regulatory capital base.

Inefficiencies in Cost Estimation Processes

480. In its Final Decision for the current access arrangement, the Authority excluded $117 million relating to inefficiency arising from poor cost estimation processes (five per cent of $910 million (net of the adjustments noted above) of investment in the transmission network and $1,436 million distribution expenditure). The five per cent reduction was based on a study carried out by Sinclair Knight Mertz (**SKM**) for Western Power and provided to the Authority following the Draft Decision. SKM identified 65 capital projects of value greater than $2 million which SKM considered were potentially adversely affected by deficiencies in cost estimation processes. SKM took a view that poor cost estimation processes may give rise to an "inefficiency factor" of a maximum of five per cent of the project value. SKM applied this factor to the total value of all projects identified by it as being affected by estimation problems to derive a value of inefficiency of $18 million (five per cent of a total value of projects of $351 million).

481. In its Final Decision the Authority considered that SKM's estimate of the extent of inefficiency arising from deficiencies in cost estimation processes may not fully capture the extent of this inefficiency. SKM determined the value as five per cent of a value of significant capital projects (greater than $2 million in value) for which the final cost exceeded the cost estimate by greater than 10 per cent, or original cost estimates could not be located. The Authority did not consider there was any reason why estimates of the extent of inefficiency arising from deficiencies in cost estimation should be so constrained. Rather, the Authority considered such inefficiencies may arise regardless of the difference between an original cost estimate and the final cost of a project (for example, a poor original cost estimate) may drive an inefficiently high cost outcome), and may arise regardless of the size of the capital project. The Authority accepted the value of five per cent applied by SKM as the level of inefficiency arising from deficiencies in cost estimation processes was appropriate but applied it to total investment for the transmission network and that part of investment in the distribution network internally funded by Western Power (that is, excluding gifted assets).

482. In its third access arrangement period submission Western Power states that "the Authority applied a 5 per cent reduction to the whole of the first access arrangement expenditure based on a lack of supporting information from Western Power". Western Power notes that it has reconsidered the issue of supporting information and that its

subsequent review of second access arrangement projects and programs that are relevant to the first access arrangement projects found that inefficiencies due to cost estimation were not apparent. They note "we have also considered our programs of work that will continue throughout the periods (such as bushfire management and wood pole replacement) that have already been regarded as complying with NFIT.

483. Western Power goes on to state that "given these recurrent programs of work do not suffer from cost inefficiencies in relation to cost estimation, we believe it is reasonable to apply the outcomes of our documentary review across the expenditure not subject to specific disallowances." Based on this view, Western Power has proposed that the whole of the $117 million should be added to the opening capital base for the third access arrangement period.

484. In its final decision for the second access arrangement the Authority noted that the report submitted by Western Power from SKM addressing the Authority's draft determination on the level of inefficiency in the first access arrangement period new facilities investment appeared to indicate that SKM had access to more information on particular capital projects than was made available to the Authority, despite the Authority having previously advised Western Power of deficiencies in information provided with the proposed access arrangement revisions and issuing Western Power with a statutory notice requiring further relevant information to be provided.

485. Given the level of scrutiny of this matter at the time of the second access arrangement review, the Authority is surprised that Western Power is now seeking to put new information forward in relation to its cost estimation processes for the first access arrangement period.

486. Western Power is also incorrect in its statement that "the Authority applied a 5 per cent reduction to the whole of the first access arrangement expenditure based on a lack of supporting information from Western Power". As noted above, the adjustment was based on the SKM report findings with the only difference being that it was applied across the total expenditure program rather than restricted to certain types of expenditure.

487. The SKM report provided by Western Power following the second access arrangement period draft decision served to confirm the Authority's view that Western Power's cost estimation process for the first access arrangement period had significant weaknesses which led to inefficiencies. The information provided by Western Power in its proposed revised access arrangement information does not change the fact that Western Power's cost estimation processes for the first access arrangement period had significant weaknesses that led to inefficiencies. Therefore, the Authority does not accept Western Power's proposal that $117 million ($ values of 30 June 2009) should be added to the opening capital base for the third access arrangement period.

Overcharging by Contractors

488. Western Power accepts that this expenditure was inefficient and should not be included in the regulatory capital base.

Inefficiencies in Planning, Design and Governance

489. In its final decision for the second access arrangement period, the Authority took the view that there had been inefficiencies in the planning and design of augmentations of the network as a result of deficiencies in forecasting of demand for services,

deficiencies in consideration of all relevant options for augmentations, and over-engineering of augmentation designs. In particular, the Authority noted information provided by Western Power subsequent to the Draft Decision confirming this view including the following:

- Western Power not using best-practice design software for the design of transmission lines that would facilitate more effective economic optimisation of transmission line design.[132]
- An absence of standard designs and guidelines for distribution assets.[133]
- Unusually restrictive design specifications for equipment, limiting the number of potential suppliers.[134]
- A lack of rigour in assessing options for network augmentations and documenting these assessments.[135]

490. Western Power was not able to provide the Authority with sufficient information to enable it to assess the extent of inefficiency on a project-by-project basis. However, for the reasons set out above, the Authority took the view that the extent of the inefficiency was greater than a nominal amount and in the order of 5 per cent.

491. In its third access arrangement submission, Western Power refers to the adjustment made by the Authority of $110.97 million in relation to inefficiencies it determined had occurred in relation to the planning, design and governance of network augmentations:

> "Western Power recognises that the determination of the Authority was based on the material it had before it at that time. However, our subsequent review of the governance and capital planning documentation outcomes for a sample of AA2 projects that are relevant to AA1 demonstrates that our options assessment and works choice is consistent with efficiently minimising costs (as defined in the Code with its emphasis on good electricity industry practice) and satisfying the NFIT requirements of the Access Code."

492. The Authority does not consider that the information included in Western Power's third access arrangement period proposal (as outlined in paragraphs 453 to 456 above) addresses the weaknesses outlined in paragraph 489 above. Therefore, the Authority has not altered its view set out in the current access arrangement Final Decision.

Overall conclusion

493. Western Power notes in its proposed revised access arrangement that, in response to the criticism of the Authority and the Authority's technical adviser, it "sharpened" its focus on initiatives to improve strategic planning, delivery and compliance processes.[136] As a result, a number of capital projects included in the forecasts for the second access arrangement period were deferred or cancelled.

494. Any improvements made by Western Power to its processes since the last access arrangement review will not change the findings of the Authority in relation to past

132 Western Power submission of 10 September 2009, Attachment F2: pp. 42, 43.

133 Western Power submission of 10 September 2009, Attachment F2: p. 44.

134 Western Power submission of 10 September 2009, Attachment F2: p. 48.

135 Western Power submission of 10 September 2009, Attachment F2: p. 61.

136 Western Power Access Arrangement Information, p. 62.

expenditure. Consequently, the Authority does not agree that the $244.43 million ($ real as at 30 June 2012) should now be added to Western Power's opening capital base for the third access arrangement period.

Required Amendment 12

Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.

Capital Base at the Commencement of the Third Access Arrangement Period

495. The Authority has calculated revised values of the capital base for the transmission and distribution networks at 30 June 2012 in accordance with the Authority's determination under this Draft Decision on the value of new facilities investment in the second access arrangement period that may be added to the capital base under section 6.51A of the Access Code, and on the value of redundant assets to be subtracted from the capital base.

496. The Authority's calculation of the revised capital base values are shown in Table 43 and Table 44 below.

Table 43 Authority's revised capital base at 30 June 2012 for the transmission network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		2,350.0	2,467.5	2,538.3
New facilities investment		198.3	151.6	146.1
Asset disposals		(5.5)	(0.3)	0.0
Depreciation		(75.3)	(80.5)	(91.1)
Accelerated depreciation		0.0	0.0	0.0
Closing asset base	2,350.0	2,467.5	2,538.3	2,593.2

Table 44 Authority's revised capital base at 30 June 2012 for the distribution network (real $ million at 30 June 2012)

	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening asset value		3,042.3	3,319.1	3,584.4
New facilities investment		436.6	437.5	537.6
Asset disposals		(0.9)	0.0	0.0
Depreciation		(154.7)	(168.2)	(186.0)
Accelerated depreciation		(4.2)	(4.1)	(4.0)
Closing asset base	3,042.3	3,319.1	3,584.4	3,932.0

Required Amendment 13

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 43 and Table 44 above.

Forecast Capital Base for the Third Access Arrangement Period

Access Code Requirements

497. Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include capital costs calculated in respect of an amount of forecast of new facilities investment that is reasonably expected to satisfy the test in section 6.51A of the Access Code.

498. The effect of sections 6.50 and 6.51A is that Western Power may notionally add forecast new facilities investment to the capital base in each year of the third access arrangement period to the extent that the forecast amounts either:

- are reasonably expected to satisfy the new facilities investment test; or
- are (or are to be) financed by a contribution, are reasonably expected to meet the requirements of the first part of the new facilities investment test (the efficiency test of section 6.52(a) of the Access Code), and the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of addition of the amount to the capital base.

Proposed Revisions

499. For the purposes of determining target revenue for the third access arrangement period, Western Power has forecast values of the capital base for the transmission and distribution networks at the commencement of each year.

500. For the third access arrangement period, Western Power proposes to only take into account, for the purposes of determining target revenue, forecast new facilities investment that is reasonably expected to satisfy the new facilities investment test. Western Power proposes to not add to the capital base any new facilities investment that is financed by contributions.

501. Western Power has forecast total capital expenditure (net of capital contributions) of $4,870.4 million over the five year third access arrangement period, with $1,838.9 million required for the transmission network and $3,031.5 million for the distribution network. Western Power has forecast that its total capital base will be around $10,414.8 million by the end of the third access arrangement period, with a closing value for the transmission network and distribution network of $4,209.8 million and $6,205.0 million, respectively. Western Power's forecast opening and closing values of the capital base for each year of the third access arrangement period for the transmission and distribution network are shown in Table 45 and Table 46.

502. Western Power's forecast capital base values are as follows.

Table 45 Western Power's forecast transmission network capital base (real $ million at 30 June 2012)[137]

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening asset value	**2,840.8**	**3,102.2**	**3,277.1**	**3,526.2**	**3,931.8**
New facilities investment[138]	337.5	255.9	340.0	503.3	390.5
Inventory	0.4	9.0	3.6	-1.6	0.3
Mid-year timing assumption	14.6	11.0	14.7	21.7	16.9
Redundant assets	0.0	0.0	0.0	0.0	0.0
Depreciation	-91.2	-100.9	-109.2	-117.8	-129.6
Accelerated depreciation	0.0	0.0	0.0	0.0	0.0
Closing asset base	**3,102.2**	**3,277.1**	**3,526.2**	**3,931.8**	**4,209.8**

Table 46 Western Power's forecast distribution network capital base (real $ million at 30 June 2012)[139]

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening asset value	**4,257.2**	**4,614.4**	**5,037.7**	**5,452.5**	**5,832.5**
New facilities investment[140]	543.6	621.5	635.8	610.5	613.8
Inventory	0.5	2.4	2.3	-1.2	2.4
Mid-year timing assumption	23.5	26.8	27.4	26.4	26.5
Redundant assets	0.0	0.0	0.0	0.0	0.0
Depreciation	-206.7	-226.9	-250.8	-255.7	-270.2
Accelerated depreciation	-3.4	-0.5	0.0	0.0	0.0
Closing asset base	**4,614.4**	**5,037.7**	**5,452.5**	**5,832.5**	**6,205.0**

503. Western Power has provided supporting information for the forecasts of new facilities investment (capital expenditure) for the third access arrangement period in Appendix A of the revised access arrangement information.

---

137 Revised access arrangement information, Section 10.2.9, Table 65. Revised access arrangement information, Section 10.3.1, Tables 66 and 67.

138 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

139 Revised access arrangement information, Section 10.2.9, Table 65. Revised access arrangement information, Section 10.3.2, Tables 68 and 69.

140 New facilities investment is net of forecast capital contributions, inventory and mid-year timing assumption adjustment.

504. Western Power has forecast substantial real increases in new facilities investment over the actual costs incurred in the current access arrangement period. These increases are attributed by Western Power to:

- improving the safety of the network through increased pole replacement and reinforcement rates and replacing unsafe customer service connections; and
- cope with maintaining network security and growth, particularly growth in peak demand.

505. Western Power acknowledges that its pole failure rate is the highest in Australia.[141] Its wood pole failure rate has been the subject of an order to repair by the Energy Safety Office. Western Power has proposed to reinforce and replace an average of 33,000 poles per year at a cost of $748 million. Western Power has estimated that its wood pole management plan will take 20 years of elevated investment before pole replacement is at a 'sustainable rate'.[142]

Submissions

506. Synergy notes Western Power's stated reasons in support of its ability to deliver the capital expenditure program during the third access arrangement period but queries whether it has seen the project and process improvements during the current access arrangement that Western Power refers to. Synergy requested the Authority to assess Western Power's claims in considering its ability to deliver the investment proposal.[143]

507. Landfill Gas and Power views the magnitude of the pole replacement program to be such that it should be addressed at a higher independent level and not be part of the access arrangement considerations.[144]

508. Alinta notes the size of the proposed third access arrangement period capital expenditure program in light of Western Power's significant underspend in the current access arrangement and queries Western Power's internal resources to meet the large expansion of its capital expenditure program. Alinta raises the issue of the AER (in National Electricity Rules regulatory decisions) taking prior period underspend/overspend into account when approving capital expenditure going forward and requests the Authority to assess Western Power's ability to deliver the capital expenditure program.[145]

509. The Chamber of Commerce and Industry (CCI) notes that the most recent Commonwealth Bank-CCI Survey of Business Expectations showed a large proportion of businesses (22 per cent) rated energy infrastructure as an area in need of attention.[146]

---

141 Revised Access Arrangement Information, Section 8.2.1, p. 176.

142 Revised Access Arrangement Information, Section 8.2.1, p. 176.

143 November 2011, Synergy, *Public Submission to the Economic Regulation Authority – Western Power's Proposed Revisions to the Access Arrangement.*

144 December 2011, Landfill Gas and Power Pty Ltd, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

145 December 2011, Alinta Energy (Australia) Pty Ltd, *Public Submission on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network*.

146 December 2011, Chamber of Commerce and Industry Western Australia, *Public Submission on the Proposed Revisions to the Access Arrangement for the Western Power Network.*

> "For business it is particularly important that Western Power is able to invest in the electricity network in support of WA's growth while also promoting the Electricity Networks Access Code 2004 objective. This balance is unlikely to be achieved through the ERA's process alone and requires strategic planning from the State Government to recognise a wider range of benefits from investment in electricity networks.
>
> CCI forecasts economic growth in WA to rise towards 7 per cent in 2012-13, led by large business investment in the resources sector. While these figures reflect some activity outside the Western Power Network, many of the State's growth areas are closely linked to this network. This underlines the need for a forward looking approach to the AA3 investment program. In this context we are broadly supportive of a revenue requirement for Western Power that recognises this need for growth and enables appropriate, efficient and realistic investment in the network."

Considerations of the Authority

510. The Authority has given consideration to Western Power's calculation of the capital base for each of the transmission and distribution networks and consistency of these calculations with the requirements of the Access Code. These considerations include the following:

    - the general method applied in calculating the capital base; and
    - determination of notional values of the capital base in each year of the third access arrangement period taking into account the assessment of forecast capital expenditure against the requirements of section 6.51A of the Access Code, and forecast values of depreciation and redundant assets.

General Method

511. Consistent with the method it has used to establish the opening capital base for the third access arrangement period, Western Power has calculated the capital base for each of the transmission and distribution networks using a roll-forward method, applied in a manner consistent with the method contemplated in the note to section 6.48 of the Access Code.

512. The roll-forward method has been favoured by utility regulators throughout Australia and is the method mandated for electricity transmission and distribution networks of the NEM under Chapters 6A and 6 of the NER.

513. The Authority is satisfied that the method used by Western Power is consistent with the Code objective.

Notional Capital Base over the Third Access Arrangement Period

Application of the Section 6.51A Test to Forecast New Facilities Investment

514. Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include capital costs calculated in respect of an amount of forecast new facilities investment that is reasonably expected to satisfy the test in section 6.51A of the Access Code.

515. Consistent with the approach adopted for the current access arrangement period, Western Power proposes to only take into account, for the purposes of determining target revenue, forecast capital expenditure that is reasonably expected to satisfy the

new facilities investment test. Western Power proposes to not add to the capital base any capital expenditure that is financed by contributions.

516. Western Power has determined amounts of forecast capital expenditure to be notionally added to the capital base by deriving a total amount of forecast capital expenditure and subtracting a forecast of capital contributions.

517. The approach taken by the Authority to assessing the forecast of new facilities investment and the amount of this forecast investment claimed by Western Power to satisfy the new facilities investment test has been to:

- assess whether the forecast of new facilities investment is reasonably expected to satisfy the efficiency test under section 6.52(a) of the Access Code; and
- assess whether Western Power has made a reasonable forecast of the amount of new facilities investment that will satisfy the new facilities investment in its entirety and that is not otherwise financed by capital contributions.

518. The Authority has addressed the forecast capital expenditure for transmission, distribution and corporate separately in the following paragraphs.

Transmission Forecast Capital Expenditure

519. Western Power's forecast third access arrangement period transmission capital expenditure is provided in Table 47 below broken down into regulatory categories.

Table 47 Transmission network capital expenditure (real $ million at 30 June 2012)[147]

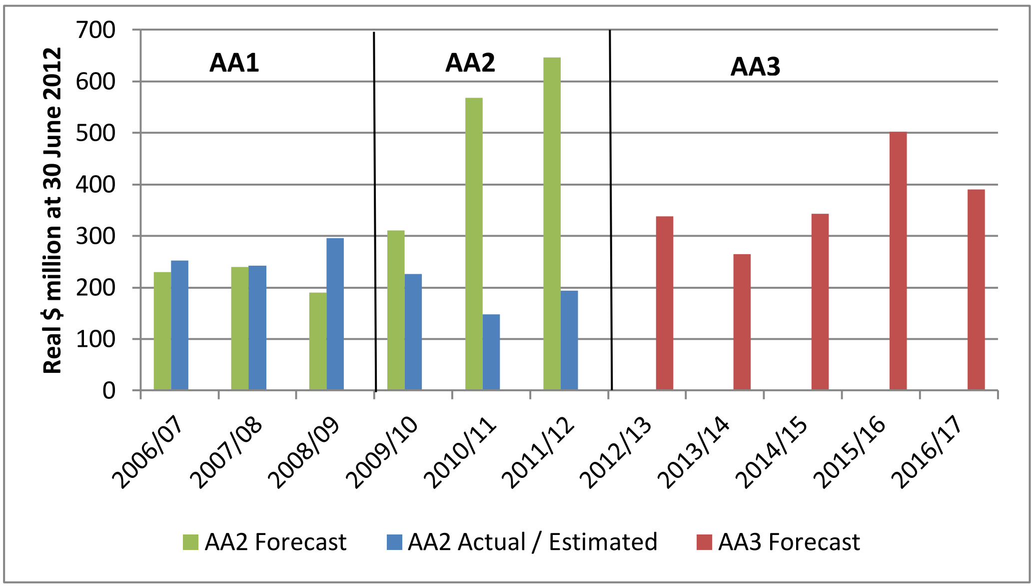
	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capacity Expansion	215.6	128.3	204.1	338.5	226.2	1,112.7
Customer Driven	31.4	31.0	30.7	30.4	31.6	155.0
Asset Replacement	30.3	32.7	32.8	32.7	34.0	162.5
Regulatory Compliance	14.0	16.7	23.3	28.9	29.4	112.3
Reliability	0.0	0.0	0.0	0.0	0.0	0.0
SCADA and Communications	14.2	11.9	12.9	18.3	18.0	75.3
Total Capital Expenditure excluding real input cost escalation	**305.5**	**220.6**	**303.7**	**448.7**	**339.2**	**1,617.7**
Western Power's Capital Expenditure forecast including real input cost escalation[148]	**308.7**	**227.9**	**321.4**	**483.7**	**372.0**	**1,713.7**

520. Figure 7 below shows Western Power's proposed forecast transmission capital expenditure net of capital contributions and inclusive of corporate expenditure and real input cost escalation for the third access arrangement period. The 2011/12 estimated capital expenditure is as originally proposed by Western Power in its proposed access arrangement information.

147 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

148 Revised Access Arrangement Information, Section 8.4, Table 43.

Figure 7 Transmission capital expenditure (real $ million at 30 June 2012)



521. Western Power has forecast transmission network capital investment to increase significantly during the third access arrangement period from the current access arrangement period and also the first access arrangement period. Apart from transmission reliability capital expenditure initiatives, which was only a very minor expenditure item during the current access arrangement period, Western Power has forecast all other categories of transmission capital expenditure to significantly increase during the third access arrangement period. In particular, capacity expansion, which represents nearly 70 per cent of net transmission network capital expenditure (excluding corporate expenditure) is the significant driver of Western Power's forecast transmission capital expenditure.

522. The Authority has considered each of the investment categories below.

Capacity Expansion

523. Western Power's forecast capacity expansion capital expenditure of $1,112.7 million during the third access arrangement period is 134 per cent higher on an average annual basis than in the current access arrangement period. This increase is driven by expenditure for the Mid West Energy Project (MWEP) and a significant increase in "thermal" augmentation of the shared transmission network. GBA, the Authority's technical advisor, has generally concluded that most of Western Power's forecast capacity expansion expenditure during the third access arrangement period is reasonable, although with some exceptions discussed below.

524. As a result, the Authority requires that Western Power's transmission capital expenditure is adjusted according to the amended forecast for capacity expansion in Table 48 below.

Table 48 Amended transmission capacity expansion capital expenditure (real $ million at 30 June 2012)[149]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capacity Expansion – proposed	215.6	128.3	204.1	338.5	226.2	1,112.7
Adjustment to remove originally proposed MWEP expenditure	(175.8)	(28.4)	(3.7)	(5.9)	(27.6)	(241.4)
Adjustment to add pre-approved MWEP NFIT amount	163.2	197.0	1.4	-	-	361.6
Adjustment to remove new CBD substation	-	(3.9)	(26.8)	(59.9)	(4.8)	(95.4)
Adjustment to remove new CBD substation supply cable	-	-	(5.1)	(22.2)	(2.4)	(29.7)
Adjustment to remove Eneabba Terminal	-	-	(2.9)	(12.7)	(1.4)	(17.0)
Adjustment to remove environmental and planning	(17.0)	(11.5)	(9.9)	(8.5)	(9.4)	(56.3)
Adjustment for reduced load growth	(9.4)	(31.0)	(57.9)	(118.3)	(29.6)	(246.2)
Capacity Expansion – amended	**176.6**	**250.5**	**99.2**	**111.0**	**151**	**788.3**

525. It should be noted Western Power cannot commit to a major augmentation before the Authority determines that it will meet the Regulatory Test as set out in chapter 9 of the Access Code. Western Power has indicated that nine of the projects included in its proposed expenditure for the third access arrangement period will require regulatory test approval. The Regulatory Test requires Western Power to demonstrate that the proposed augmentation maximises the net benefit after considering alternative options and that adequate public consultation has been conducted.

149 Real cost escalation has been removed for comparison purposes, except for the adjustment to remove the originally proposed MWEP (stage 1) expenditure which includes real cost escalation in 2012/13, 2013/14 and 2014/15 with the pre-approved MWEP NFIT amount

526. If Western Power chooses to proceed with a project which the Authority has removed from Western Power's forecast transmission capital expenditure (or proceed with a new capacity expansion project that has not been included in Western Power's proposed revised access arrangement) then, providing the expenditure is considered by the Authority to be efficient at the next access arrangement review and that it meets other elements of the new facilities investment test, the expenditure will be added to the opening capital base for the fourth access arrangement period. Furthermore, Western Power will be eligible to receive a return on this investment from the date it is incurred, as calculated by the Investment Adjustment Mechanism.

527. Western Power is also able to obtain pre-approval for the amount of expenditure which can be rolled into the capital base by lodging a new facilities investment test application at any time under Section 6.71 of the Access Code.

528. The Authority's specific amendments to Western Power's proposed forecast capacity expansion capital expenditure are discussed below.

Mid West Energy Project

529. Western Power issued an errata to its proposed access arrangement, as a significant amount of expenditure relating to the Mid West Energy Project (**MWEP**) had not been included in its proposed access arrangement in error. Subsequent to the errata, the Authority released its final decision on Western Power's pre-approval NFIT application for the MWEP in January 2012. The Authority's final decision was to pre-approve the inclusion of $377.8 million (real dollars at 30 June 2010) for the MWEP. Western Power provided a breakdown of the expenditure and $340.5 million (real dollars at 30 June 2010) is forecast to be spent during the third access arrangement period. The remaining expenditure from the pre-approval has already been spent by Western Power prior to the third access arrangement period. The Authority has only allowed the appropriate proposed forecast expenditure which it has decided meets the NFIT.

530. Western Power has also included around $35.4 million for stage 2 of the MEWP. However, as there is considerable uncertainty regarding when this project will proceed, the Authority is not satisfied that this expenditure would satisfy the NFIT and has removed it from forecast capital expenditure.

CBD Substation and Supply Cable

531. Western Power's capacity expansion capital expenditure forecasts for the third access arrangement period include a $95.4 million project to construct a new CBD substation. GBA is not satisfied that the construction of a new substation in the CBD during the third access arrangement period is consistent with the least cost approach to addressing emerging supply issues within the CBD.[150] GBA also noted that even if a new substation is needed based on information from Western Power, it saw little risk in deferring the project to the fourth access arrangement period, and that this additional time would provide Western Power more time to undertake a strategic planning study. Consistent with its recommended deferral of the new CBD substation, the associated supply cable at a forecast cost of $29.7 million should also be deferred.

[150] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 77.

532. The Authority is concerned that Western Power has not given due consideration to identifying the least cost approach to addressing a network supply issue. Considering that GBA had identified alternative options identification as a governance issue in the current access arrangement period, the Authority is concerned that Western Power's governance needs to improve quickly to ensure that all options are considered to address supply issues and that the least cost option is identified. As a result, the Authority considers that forecast expenditure for a new CBD substation and associated supply cable be removed from Western Power's forecast transmission capital expenditure.

Eneabba Terminal Station

533. Western Power has forecast to spend $17 million on the construction of a terminal station at Eneabba during the third access arrangement period. GBA has reviewed this expenditure and considers that this expenditure should not be included in Western Power's forecast transmission capital expenditure. GBA noted that the Eneabba terminal station is required to support potential new wind generation projects around Eneabba. However, GBA considers that the timing around this potential new generation is speculative and that the economics of wind farm development are still uncertain. GBA considers that, should there be a need for the Eneabba terminal station during the third access arrangement period, then the investment adjustment mechanism could apply to allow recovery of costs during the fourth access arrangement period.[151] The Authority agrees with GBA's reasoning that current customers should not have to pay in advance for this uncertain investment and that Western Power may apply the investment adjustment mechanism to this investment providing it met NFIT requirements.

Environmental and Planning

534. Western Power has forecast expenditure of around $56.3 million on environmental and planning costs during the third access arrangement period. GBA reviewed this expenditure and considers that this expenditure would not meet NFIT requirements. GBA noted that, prior to 2011/12, no expenditure was recorded to this category as all expenditure on environmental and planning issues was directly attributed to individual capital expenditure projects.[152] The Authority has reviewed the advice from GBA and agrees that the expenditure for environmental and planning, which totals $56.3 million, does not meet the requirements of the new facilities investment test.

Reduced Load Growth

535. Western Power has forecast its capacity expansion capital expenditure on the basis of the 10 per cent probability of exceedence (POE), central load forecast in its 2010 Annual Planning Report. Western Power's 2010 Annual Planning Report indicated that peak demand in 2018 would reach 5,225 MW. Subsequent to Western Power's access arrangement submission, Western Power's 2011 Annual Planning Report has become available. Western Power now expects that peak demand will only reach 4,738 MW. Western Power's 2011 Annual Planning Report states that the peak demand is currently 4,005 MW, set on 25 February 2011. GBA has noted that this implies that, whereas Western Power's growth driven capital expenditure was

151 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 78-79.

152 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 79-80.

intended to support growth in demand of 1,220 MW in its access arrangement submission, the 2011 Annual Planning Report now suggests that 733 MW of demand growth is now required. GBA notes that this suggests that up to 40 per cent of Western Power's growth driven capital expenditure could be deferred to the fourth access arrangement.

536. As a result, GBA has recommended a reduction to the transmission supply and transmission voltage capital expenditure by 40 per cent. GBA has also identified load driven projects (the 132 kV Mungarra-Geraldton and Kojonup-Albany lines) which can be deferred and that proposed expenditure on the Mungarra-Geraldton line is not consistent with the proposed MWEP (northern section).[153]

537. The Authority agrees with GBA's assessment of the reduced need for growth driven capital expenditure based on Western Power's latest available estimates of peak demand growth and the deferral of the 132 kV Mungarra-Geraldton and Kojonup-Albany lines.

Table 49 Amended transmission network capacity expansion for reduced load growth (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Reduction in transmission supply capital expenditure	(8.2)	(28.8)	(30.4)	(19.8)	(19.7)
Reduction in transmission voltage capital expenditure	(1.1)	(2.2)	(8.2)	(14.0)	(0.9)
Deferral of the Mungarra-Geraldton line	-	-	(6.8)	(29.9)	(3.2)
Deferral of the Kojonup-Albany line	-	-	(12.5)	(54.6)	(5.9)
Total reduced load growth adjustment	**(9.4)**	**(31.0)**	**(57.9)**	**(118.3)**	**(29.6)**

Customer Driven

538. Western Power's forecast net customer driven capital expenditure of $155 million during the third access arrangement period is 292 per cent higher on an average annual basis than the current access arrangement period. This has been driven by a 38 per cent increase in forecast gross customer driven capital expenditure and an 8 per cent reduction in forecast capital contributions on an average annual basis than the current access arrangement period. GBA considers that this forecast capital expenditure is not entirely reasonable and has recommended amendments to the forecasts.

153 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 80-82.

539. As a result, the Authority requires that Western Power's transmission capital expenditure is adjusted according to the amended forecast for customer driven capital expenditure in Table 50.

Table 50 Amended forecast of transmission customer driven capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Customer driven – proposed	72.1	71.2	70.5	69.9	70.7
Capital contributions – proposed	(40.7)	(40.2)	(39.8)	(39.5)	(39.1)
Net customer driven – proposed	31.4	31.0	30.7	30.4	31.6
Customer driven – amended	**57.5**	**56.8**	**56.2**	**55.8**	**56.4**
Capital contributions – amended	**(37.4)**	**(36.9)**	**(36.5)**	**(36.2)**	**(36.7)**
Net customer driven – amended	**20.1**	**19.9**	**19.7**	**19.5**	**19.7**

540. GBA noted that Western Power has stated that its gross customer driven capital expenditure forecast was based on historic level adjusted for identifiable drivers. However, GBA noted that its forecast appears high given that the 38 per cent increase is much higher than the expected network growth rate. GBA considers that the forecast average gross customer driven capital expenditure should be adjusted so it exceeds the average in the current access arrangement period by only 10 per cent.

541. GBA noted that during the first and current access arrangement periods, capital contributions offset on average 65 per cent of gross customer driven capital expenditure. However, Western Power has proposed that this offset be reduced to 56 per cent of gross customer driven capital expenditure for the third access arrangement period. GBA noted that Western Power has not provided any rationale for this reduction and considers that the forecast capital contributions should be increased to the historic levels.[154]

542. The Authority agrees with GBA's assessment that the net customer driven capital expenditure should be adjusted to reflect the forecasts for gross customer driven expenditure and capital contributions recommended by GBA as indicated in Table 50. As noted in paragraph 526, the investment adjustment mechanism would apply to this category of expenditure and as a result, any additional expenditure which Western Power may need to spend (and which meets the NFIT) can be compensated for in the fourth access arrangement period.

Other Expenditure

543. GBA considered that Western Power's remaining forecast transmission capital expenditure for asset replacement, regulatory compliance and SCADA and communications are generally reasonable. Key points of note include:[155]

[154] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 84.

[155] March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 7.

- asset replacement capital expenditure is forecast to increase by 55 per cent on average in real terms from the current access arrangement period. This increase is driven almost entirely by a substantial increase in the rate of replacement of indoor circuit breakers. GBA reviewed the forecast replacement of indoor circuit breakers and considered it reasonable on safety related grounds.
- regulatory compliance capital expenditure is forecast to increase by 52 per cent on average in real terms from the current access arrangement period with approximately half of this expenditure for cross-arm replacement and pole management. This is not an unexpected situation as Western Power is under pressure to improve the quality of its overhead lines in extreme and high fire risk areas.
- SCADA and communications expenditure is forecast to increase by 60 per cent on average in real terms from the current access arrangement period. The bulk of this increased expenditure is on asset replacement. Western Power states that this is for the upgrade of the XA-21 master station in System Management's control room and the completion of a number of large microwave replacements.
  - The master station hardware is located in System Management's control room. GBA considered whether the master station assets should be included in Western Power's capital base and, consequently, whether master station asset replacement costs should be funded from regulated transmission revenues. GBA's concern arises from the ring-fenced status of System Management and the fact that System Management's primary function under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* and the Market Rules is to operate the SWIS in a secure and reliable manner. GBA notes that it appears that, while the System Management owns software associated with generator scheduling, the control room and master station are still owned by Western Power, and System Management does not pay rental for the use of this master station. GBA did not find a documented agreement or contract between Western Power and System Management that defined the boundary between Western Power and System Management owned assets or specified how power system control costs are to be apportioned. This, in GBA's view, is not a satisfactory situation. It is possible that some costs are being carried by Western Power that should be carried by System Management as they relate to the performance of System Management's functions.

544. The Authority agrees with the findings by GBA and is particularly concerned with the SCADA and communications expenditure for the ring-fenced System Management. It appears to the Authority that the entire amount for the master station expenditure (which according to Table 41 of Attachment A of Western Power's revised access arrangement information is $15.5 million) should be removed from forecast capital expenditure. On page 132 of Attachment A of Western Power's revised access arrangement information, Western Power notes that the master station is a business critical system that provides the ring-fenced System Management real-time visibility and control of the generation and transmission network, including outage and fault management, and provides data to support the Wholesale Electricity Market Rules. If this is the case, then the Authority considers that System Management should pay for it, not Western Power's customers. If Western Power does need to use the master station for its activities then it should provide detailed information of the need, in its response to this draft decision. As a result, the Authority requires Western Power's

transmission capital expenditure to be adjusted to the amended forecast of master station expenditure in Table 51.

Table 51 Amended forecast of transmission SCADA & Communications capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
SCADA & Communications – Master Station XA/21 – proposed	2.8	3.2	2.8	3.1	3.5
SCADA & Communications – Master Station XA/21 – amended	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Amended Transmission Network Capital Expenditure

545. The Authority's amended transmission network capital expenditure for the third access arrangement period is summarised below in Table 52 below.

Table 52 Amended transmission network capital expenditure (real $ million at 30 June 2012)[156]

	2012/13	2013/14	2014/15	2015/16	2016/17
Capacity Expansion	176.6	250.5	99.2	111.0	151.0
Customer Driven	20.1	19.9	19.7	19.5	19.7
Asset Replacement	30.3	32.7	32.8	32.7	34.0
Regulatory Compliance	14.0	16.7	23.3	28.9	29.4
Reliability	0.0	0.0	0.0	0.0	0.0
SCADA and Communications	11.4	8.7	10.1	15.2	14.5
Total Amended Transmission Capital Expenditure	**252.4**	**328.5**	**185.1**	**207.3**	**248.6**
Western Power's Proposed Transmission Capital Expenditure	**305.6**	**220.6**	**303.7**	**448.7**	**339.2**

Distribution Forecast Capital Expenditure

546. Western Power's forecast third access arrangement period distribution net capital expenditure (excluding capital contributions and gifted assets) is provided in Table 53 below, broken down into regulatory categories.

156 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

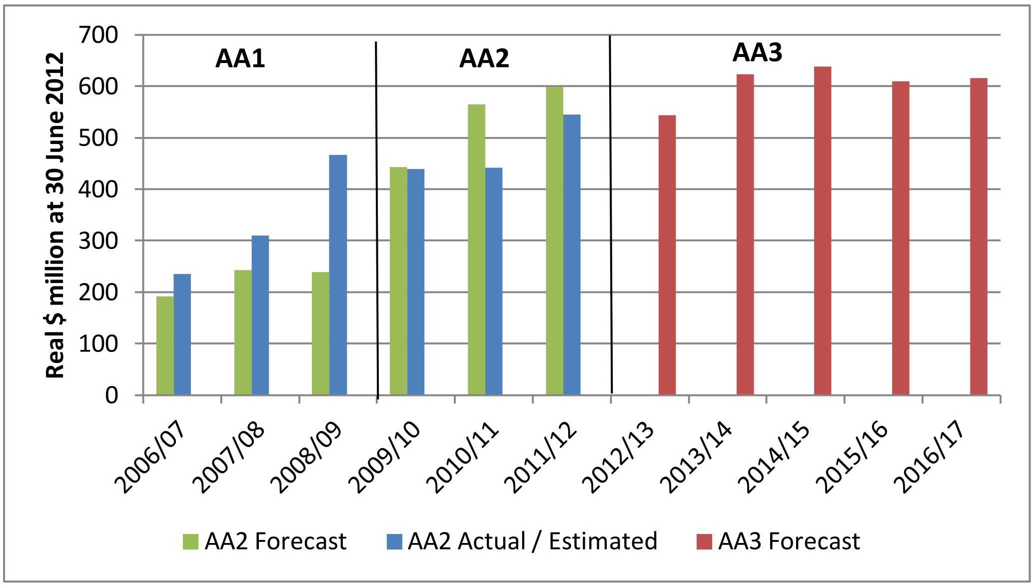
Table 53 Distribution network capital expenditure (real $ million at 30 June 2012)[157]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Capacity Expansion	65.1	72.3	82.7	82.4	84.3	386.7
Customer Access	132.1	129.4	130.2	128.5	129.1	649.4
Asset Replacement	157.7	166.0	170.8	179.6	190.0	864.2
Regulatory Compliance	99.1	103.4	103.6	72.7	78.4	457.2
Metering Asset Replacement	15.1	47.3	46.5	41.9	17.0	167.8
Reliability	0.6	0.6	0.6	0.6	0.6	3.0
SCADA and Communications	4.8	5.7	6.6	3.8	6.7	27.6
Smart Grid	2.5	23.9	26.2	19.7	15.0	87.3
State Underground Power Program	9.8	4.7	0.0	0.0	0.0	14.5
Total Capital Expenditure excluding real input cost escalation	**486.9**	**553.5**	**567.1**	**529.2**	**521.0**	**2,657.7**
Western Power's Capital Expenditure forecast including real input cost escalation[158]	**495.9**	**575.1**	**605.0**	**578.0**	**583.2**	**2,837.2**

157 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

158 Revised Access Arrangement Information, Section 8.5, Table 46.

Figure 8 Distribution network capital expenditure (real $ million at 30 June 2012)



547. Figure 8 above shows Western Power's proposed forecast distribution capital expenditure net of capital contributions and inclusive of real input cost escalation for the third access arrangement period. The 2011/12 estimated capital expenditure is as originally proposed by Western Power in its proposed access arrangement information. Apart from 2012/13, Western Power's forecast net distribution capital expenditure will be above Western Power's estimated 2011/12 expenditure in real terms.

548. While the aggregate net distribution capital expenditure for the third access arrangement period has increased from Western Power's estimated 2011/12 expenditure there has also been large compositional changes in the types of capital expenditure. Western Power has forecast to spend considerably less, on average, than the current access arrangement period on reliability initiatives, the SUPP and customer connection capital expenditure. While Western Power has forecast to spend considerably more, on average, on asset replacement, capacity expansion, regulatory compliance, metering asset replacement and Smart Grid capital expenditure.

Capacity Expansion

549. Western Power's forecast capacity expansion capital expenditure of $386.7 million during the third access arrangement period is 55 per cent higher on an average annual basis than the current access arrangement period. GBA considers that most of Western Power's forecast expenditure is reasonable. However, GBA has recommended that some adjustment to Western Power's forecast is required.

550. Taking account of GBA's advice, the Authority considers that Western Power's distribution capital expenditure should be adjusted as set out in Table 54 below.

Table 54 Amended distribution capacity expansion capital expenditure for the third access arrangement (real $ million at 30 June 2012)[159]

	2012/13	2013/14	2014/15	2015/16	2016/17
Capacity Expansion – proposed	65.1	72.3	82.7	82.4	84.3
Adjustment to transmission driven distribution capital expenditure	(5.3)	(3.1)	(5.7)	(10.0)	(3.8)
Adjustment for reduced demand growth	(9.0)	(11.8)	(13.2)	(10.5)	(12.1)
Capacity Expansion – amended	**50.8**	**57.4**	**63.8**	**61.9**	**68.4**

551. The majority of this expenditure is for minor distribution network capacity expansion projects to catch up on the deferred investment during the current access arrangement period. This expenditure is focussed on reducing the risk of outages on highly loaded feeders. GBA noted that utilisation of some of Western Power's distribution feeders is greater than 80 per cent which is high by industry standards.

552. However, GBA did not consider that the transmission driven distribution capital expenditure forecast by Western Power to be reasonable. GBA considered that it was difficult to see why the distribution costs should be, on average, greater than about 10 per cent of the associated costs of the transmission equipment that drives this expenditure. Western Power's third access arrangement period forecasts were well above 10 per cent, particularly for 2012/13 which represented 36 per cent. Western Power's actual current access arrangement transmission driven distribution capital expenditure was well below 10 per cent of the associated transmission capital expenditure. The Authority agrees with GBA's recommendation and believes that the transmission driven capital expenditure should be limited to 10 per cent of the transmission costs which drive this expenditure and notes that this 10 per cent limit is conservative based on historical data.

553. As discussed above in relation to transmission capital expenditure, the Authority considers that Western Power's 2011 Annual Planning Report (**APR**) demand forecasts should be used as a basis for forecasting capital expenditure as these forecasts were the most recent estimates of demand growth. The 2011 APR forecast that demand growth during the third access arrangement period would be 40 per cent lower than Western Power assumed when it made its forecasts for growth capital expenditure requirements for third access arrangement period.

554. As transmission driven distribution capital expenditure is directly related to the level of transmission driven supply capital expenditure which the Authority has decided to reduce by 40 per cent, it seems reasonable to the Authority that this expenditure is also reduced by 40 per cent. Also, GBA has noted that the reduction in demand

159 Real cost escalation has been removed for comparison purposes.

growth should also correspond with the need for less minor distribution capacity expansion projects. However, GBA has only recommended a 20 per cent reduction rather than a 40 per cent reduction, noting that it would not expect the correlation to be as direct as that for transmission driven capital expenditure.[160] The Authority agrees that the reduction for minor distribution capacity expansion projects should be less than the 40 per cent of peak demand growth and considers that 20 per cent is a reasonable approximation.

Asset Replacement

555. Western Power's forecast asset replacement capital expenditure of $864.2 million during the third access arrangement period is 54 per cent higher on an average annual basis than in the current access arrangement. Western Power's proposed expenditure on its wood pole replacement and reinforcement has increased by almost 50 per cent compared to the current access arrangement period and forms 76 per cent of the proposed asset replacement expenditure. As noted by GBA, Western Power's trend of increasing asset replacement capital expenditure is consistent with the experience of other distribution network service providers, as assets installed during the high growth period of the 1960s and 1970s reach the end of their economic life.

556. In its review, GBA considered that generally the expenditure proposed by Western Power for asset replacement was reasonable, particularly as the replacement of the identified assets was necessary to reduce safety risks caused by the network.[161]

557. The poor condition of its wood pole population poses a high risk for Western Power because of the risk to public safety from unassisted wood pole failures and the potential for such failures to start bush fires that cause extensive property damage. Western Power's wood pole failure rate is significantly higher than other Australian distribution network service providers.

558. Western Power is proposing to significantly increase its wood pole replacement and reinforcement rates during the third access arrangement period and has included forecast capital expenditure of $748 million. Based on its current assessment of the condition of the wood pole population, Western Power considers it will take 20 years of elevated investment before it can reach a sustainable rate of replacement. Western Power has considered more aggressive timescales but considers the 20 year management plan is the most achievable approach.

559. In September 2009 Western Power was issued with an Order by EnergySafety which required, among other things, that all unsupported rural poles which did not comply with required standards should be replaced or reinforced by 2015. This Order followed EnergySafety audits into Western Power's management of its distribution wood pole population that were undertaken in 2007 and 2009.

560. The Authority understands that EnergySafety considers Western Power's proposed wood pole management program is inadequate and that Western Power's preferred investment approach does not fully meet the Order's requirements.

---

160 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 97.

161 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.2.

561. Western Power's unassisted wood pole failure rate has also been the subject of a recent inquiry by the Standing Committee on Public Administration of the Legislative Council of the Western Australian Parliament.[162] The report of the Legislative Council's Standing Committee on Public Administration and the asset management review[163] undertaken for the Authority by GHD were both critical of aspects of Western Power's management of its wood pole replacement program.

562. The Authority notes that the level of wood pole renewal and replacement required in order to comply with the Safety Order is a matter for Western Power to resolve with the technical regulator, EnergySafety and is not for the Authority to determine.

563. The Authority's technical adviser considers that improvements in the efficiency with which wood pole inspections are undertaken and wood pole replacements are implemented are available, particularly if Western Power successfully addresses issues related to records management. However, the Authority considers any efficiency improvements should drive an increase in the rate of pole replacement and reinforcement rather than a reduction in the actual expenditure.

564. The Authority is aware that another network service provider has carried out an evaluation comparing steel and wood poles and, in its' particular situation, established that steel poles had a lower life cycle cost and provided additional benefits compared with wood poles. The Authority expects that Western Power has undertaken similar analysis.

565. Potentially the investment needs for wood pole management may change as Western Power further develops its understanding of what is required. To ensure that Western Power is incentivised to do this in an efficient manner, the Authority has decided that, for the third access arrangement period, expenditure relating to wood pole management should be subject to the investment adjustment mechanism. This will then enable expenditure higher than forecast to be recovered to the extent that it is demonstrated to be efficient expenditure, and will provide Western Power with a return on that investment from the date it is incurred. Alternatively, the provisions of the Access Code enable Western Power to apply to the Authority at any time for pre-approval of capital expenditure forecasts. All of these provisions ensure Western Power is not constrained to only spend what is allowed in the current forecast.

The Authority has not adjusted Western Power's forecast distribution asset replacement capital expenditure.

---

162 *Unassisted Failure:* Report 14, Standing Committee on Public Administration, Report 14, Legislative Council, Parliament of Western Australia, January 2012.

163 GHD Asset Management System Review Final Report October 2011.

Required Amendment 14

The proposed access arrangement revisions must be amended to include expenditure relating to wood pole management in the investment adjustment mechanism.

Metering Asset Replacement

566. Western Power's forecast expenditure of $167.8 million during the third access arrangement period for meter asset replacement covers two programs – new and replacement of standard meters and the installation of three phase smart meters to replace 280,000 three phase meters that do not comply with section 6.8(d) of the Metering Code. GBA considers that most of Western Power's forecast expenditure is reasonable. However, GBA recommended that some adjustment to Western Power's forecast is required.

567. As a result, the Authority requires that Western Power's distribution capital expenditure is adjusted according to the amended forecast for metering asset replacement in Table 55 below.

Table 55 Amended distribution metering asset replacement capital expenditure for the third access arrangement (real $ million at 30 June 2012)[164]

	2012/13	2013/14	2014/15	2015/16	2016/17
Metering Asset Replacement – proposed	15.1	47.3	46.5	41.9	17.0
Adjustment to new and replacement of standard meters capital expenditure	(1.4)	(1.3)	(1.3)	(1.3)	(1.3)
Adjustment to smart meters capital expenditure	(0.1)	(1.7)	(1.7)	(1.4)	(0.2)
Metering Asset Replacement – amended	**13.6**	**44.3**	**43.5**	**39.2**	**15.5**

568. Western Power's new and replacement meter component has reduced by 8 per cent on average in the third access arrangement period compared to the current access arrangement period. However, this expenditure line item does not include three phase meters in the third access arrangement period as these are being replaced under the smart meter program. Western Power has stated that one-third of the 30,000 meters it replaced each year in the current access arrangement period were three phase meters. As a result, to make a fair comparison with the expenditure level in the current access arrangement period, GBA took account of the 10,000 three

164 Real cost escalation has been removed for comparison purposes.

phase meter replacements per annum which have not been included in the third access arrangement period expenditure for new and replacement of standard meters. GBA concluded that it would have expected this line item to have decreased by 18 per cent in the third access arrangement period. As a result, GBA has proposed a 10 per cent reduction in the forecast for new and replacement meters.

569. GBA considered that Western Power's forecast costs for its smart meter program to replace non-compliant three phase meters was overstated by up to 15 per cent compared to benchmarked results from the Victorian advance meter rollout program. GBA had noted that this analysis did not provide for the allocation of indirect costs. However, even with an allocation of indirect costs, GBA considered that the forecast cost of the smart meter program was still overstated. As a result, GBA has recommended a 5 per cent reduction to the forecast cost of this program.[165]

570. The Authority considers that it is reasonable that the new and replacement of standard meters capital expenditure be reduced by 10 per cent to reflect the current access arrangement levels of expenditure and that the smart meter program be reduced by 5 per cent as the costs for this program appear to be overstated based on benchmarking analysis.

Other Expenditure

571. GBA considers that Western Power's remaining forecast distribution capital expenditure for customer access, regulatory compliance, reliability, SCADA and communications, smart grid and the SUPP are generally reasonable. Key points of note include:[166]

- customer access costs are forecast to be lower on average in real terms compared to the current access arrangement. However customer access expenditure is very difficult to forecast as it is almost entirely out of Western Power's control.
- regulatory compliance will increase by 19 per cent on average in real terms from the current access arrangement period. This has been driven by expenditure that will replace or refurbish assets that are at risk of initiating bush fires, improve overhead connection for increased public safety, target a reduction in the number of outages lasting longer than 12 hours that trigger penalty payments, and enhancements to the low voltage network to meet the requirements of the *Electricity Act 1945*.
- distribution reliability expenditure has decreased by 95 per cent on average in real terms from the current access arrangement. This reflects Western Power's perception that customers are generally satisfied with the level of service currently provided.
- SCADA and communications for distribution is quite small relative to transmission SCADA and communications expenditure. Given this and that distribution SCADA is important to network functionality, GBA considers this expenditure reasonable.

165 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 99-100.

166 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, Section 8.

- Smart Grid forecast expenditure in the third access arrangement period is expected to increase significantly from the current access arrangement, as Western Power has decided to replace 3 phase meters with new smart grid meters. Western Power has undertaken studies that show that the costs of implementing a smart grid program are substantial but that the benefits, particularly to customers through lower wholesale electricity prices, would more than offset this with a net benefit of $208 million over time.
  - GBA considered that the quantified societal benefits should be monitored on an ongoing basis and be compared to the modelled results.
- Western Power has forecast net expenditure (capital contributions are excluded) for the SUPP of $14.5 million for the first two years of the third access arrangement period. This expenditure will meet Western Power's obligations under round 5 of the SUPP. Western Power currently has no commitment to further rounds of the SUPP, so no additional capital expenditure has been forecast for the remaining years of the regulatory period.

572. The Authority agrees with the findings by GBA that Western Power's forecast expenditure for distribution customer access, regulatory compliance, reliability, SCADA and communications, smart grid and the SUPP are reasonable. The Authority is particularly interested in following Western Power's efforts to improve its regulatory compliance during the third access arrangement period due to the significant safety issues and risks posed and also in monitoring the smart grid expenditure to see if the societal benefits do materialise as expected by Western Power.

Amended Distribution Network Capital Expenditure

573. The Authority's amended distribution network capital expenditure for the third access arrangement period is summarised below in Table 56.

Table 56 Amended distribution network capital expenditure (real $ million at 30 June 2012)[167]

	2012/13	2013/14	2014/15	2015/16	2016/17
Capacity Expansion	50.8	57.4	63.8	61.9	68.4
Customer Access	132.1	129.4	130.2	128.5	129.1
Asset Replacement	157.7	166.0	170.8	179.6	190.0
Regulatory Compliance	99.1	103.4	103.6	72.7	78.4
Metering Asset Replacement	13.6	44.3	43.5	39.2	15.5
Reliability	0.6	0.6	0.6	0.6	0.6
SCADA and Communications	4.8	5.7	6.6	3.8	6.7
Smart Grid	2.5	23.9	26.2	19.7	15.0
State Underground Power Program	9.8	4.7	0.0	0.0	0.0
Total Amended Distribution Capital Expenditure	**471.1**	**535.6**	**545.2**	**506.0**	**503.6**
Western Power's Proposed Distribution Capital Expenditure	**486.9**	**553.5**	**567.1**	**529.2**	**521.0**

Corporate Capital Expenditure

574. Western Power's forecast third access arrangement period corporate capital expenditure is provided in Table 57 below broken down into regulatory categories. The majority of Western Power's proposed corporate capital expenditure relates to projects that are currently underway, including:

- property purchases;
- purchasing plant and equipment;
- refurbishing head office and major depots;
- replacing IT hardware and software; and
- delivering major enterprise systems.

167 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

Table 57 Corporate capital expenditure (real $ million at 30 June 2012)[168]

	2012/13	2013/14	2014/15	2015/16	2016/17
IT	43.9	41.5	25.5	27.1	27.6
Business Support	31.9	30.7	21.9	21.9	17.8
Total Capital Expenditure	**75.7**	**72.2**	**47.4**	**49.0**	**45.5**

Information Technology

575. The majority of Western Power's proposed forecast for IT capital expenditure is dedicated to new IT infrastructure and improving major enterprise level information systems.

576. The remaining IT expenditure ($39.6 million) relates to "business as usual" expenditure. This expenditure relates to undertaking ongoing minor business system enhancements. Western Power's business as usual IT expenditure is forecast to increase by 73 per cent per annum on average over its actual current access arrangement capital expenditure. Western Power has not provided an explanation for the significant increase. As a result, GBA considers that this expenditure should be adjusted on a pro-rata basis to be consistent with the average current access arrangement period expenditure.[169]

577. Without an explanation for the significant increase in business as usual IT expenditure, the Authority considers that the expenditure should be adjusted on a pro-rata basis to ensure it is consistent with the annual average of actual current access arrangement expenditure. As a result, the Authority requires that Western Power's information technology capital expenditure is adjusted according to the amended forecast in Table 58.

Table 58 Amended Forecast of Information Technology capital expenditure (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
IT – Proposed	43.9	41.5	25.5	27.1	27.6
Adjustment to IT business as usual expenditure	(3.1)	(3.1)	(3.1)	(3.5)	(4.0)
IT – Amended	**40.8**	**38.4**	**22.4**	**23.6**	**23.6**

Business Support

578. Western Power's business support capital expenditure reflects refurbishment and construction of its head office and new depot locations at Busselton and Jerramungup to accommodate an increased capital works program, as well as capital items to support office and depot accommodation. GBA considered that Western Power's

168 Capital expenditure is exclusive of real cost escalation for comparison purposes.

169 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, p. 109.

forecast capital expenditure for business support was reasonable.[170] Without any conflicting information to suggest otherwise, the Authority also considers that this expenditure is reasonable.

Amended Corporate Capital Expenditure

579. The Authority's amended corporate capital expenditure for the third access arrangement period is summarised below in Table 59. The amended corporate expenditure will be allocated on a pro-rata basis to the transmission and distribution notional new facilities investment.

Table 59 Amended corporate capital expenditure for third access arrangement (real $ million at 30 June 2012)[171]

	2012/13	2013/14	2014/15	2015/16	2016/17
IT	40.8	38.4	22.4	23.6	23.6
Business Support	31.9	30.7	21.9	21.9	17.8
Total Corporate Capital Expenditure	**72.7**	**69.1**	**44.3**	**45.5**	**41.4**

Indirect Capital Expenditure

580. As noted in paragraphs 291 to 293, the Authority reduced the amount of indirect costs allocated to operating expenditure by 13.7 per cent to limit the significant increases proposed by Western Power. Western Power proposed an unexplained 17.3 per cent increase in the indirect cost allocation for operating expenditure between 2010/11 and 2012/13. As a result, the escalation of indirect operating expenditure was based on GBA's advice that the network operations net growth escalation factor was reasonable. The Authority agrees with GBA's advice that a similar adjustment to the indirect costs allocated to capital expenditure is also warranted.

581. As a result, the Authority requires that Western Power's indirect costs for capital expenditure is adjusted according to the amended forecast in Table 60.

Table 60 Amended Forecast of Indirect Cost Allocation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Indirect – Proposed	136.0	138.9	145.6	153.5	144.3
Indirect – Amended	**117.4**	**119.9**	**125.7**	**132.5**	**124.6**

Input Cost Escalation

582. As indicated in Table 32 and Table 33, the Authority has amended the real labour and materials escalation factors proposed by Western Power. The Authority considered that the proposed escalation factors overstated reasonable escalation factors for these input costs.

170 March 2012, Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, pp. 110-111.

171 Capital expenditure is net of forecast capital contributions and has removed real cost escalation for comparison purposes.

583. The Authority has calculated a notional amount of real cost escalation for labour for Western Power based on its recommended escalation factors and expenditure allowed for transmission and distribution. The Authority has amended the total distribution and transmission capital expenditure forecasts accordingly.

584. The total impact of the labour escalation factors was forecast by Western Power to be $288.3 million for capital expenditure[172] (calculated in real $ as at 30 June 2012). The Authority has estimated that only $183.4 million is reasonable.

585. The total impact of the materials escalation factors was forecast by Western Power to be $13 million for capital expenditure[173] (calculated in real $ terms as at 30 June 2012). The Authority has not allowed any increase for materials escalation.

Table 61 Amended Real Input Escalation (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Labour Escalation – Proposed Capital Expenditure	13.9	31.9	57.5	85.9	99.1
Labour Escalation – Amended Capital Expenditure	**13.3**	**24.0**	**37.1**	**47.4**	**61.6**
Materials Escalation – Proposed Capital Expenditure	-0.3	0.7	2.8	4.6	5.2
Materials Escalation – Amended Capital Expenditure	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Conclusion on Application of the Section 6.51A Test

586. Under section 6.51 of the Access Code, the forecast total costs for providing covered services for the third access arrangement period may include costs in relation to forecast new facilities investment that is reasonably expected to satisfy the test in section 6.51A when the forecast new facilities investment is forecast to be made.

587. After having regard to information provided by Western Power and other advice, the Authority considers that the entire amount of forecast new facilities investment that is not subject to a contribution, and that Western Power proposes to take into account in determining the forecast total costs, does not satisfy the new facilities investment test and, hence, does not satisfy the test of section 6.51A or the requirements of section 6.51.

588. The Authority considers that a lesser amount of forecast new facilities investment (capital expenditure) satisfies the requirements of section 6.51 of the Access Code, as detailed in paragraphs 514 to 585. For the purposes of this Draft Decision, the Authority has determined the total capital cost of providing covered services as set out in Table 62.

[172] Ibid, p. 193.

[173] Ibid, p.193.

Table 62 Amended forecast capital expenditure (real $ million at 30 June 2012)[174] [175] [176] [177]

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Transmission – proposed	337.5	255.9	340.0	503.3	390.5	1,827.2
Transmission – amended	**275.0**	**353.1**	**200.6**	**225.2**	**274.4**	**1,328.3**
Distribution – proposed	543.5	621.4	635.8	610.4	613.8	3,025.0
Distribution – amended	**515.9**	**586.6**	**590.1**	**557.9**	**559.8**	**2,810.3**
Total – proposed	881.0	877.3	975.8	1,113.8	1,004.3	4,852.2
Total – amended	**790.9**	**939.7**	**790.7**	**783.1**	**834.2**	**4,138.6**

Required Amendment 15

The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as listed in Table 62.

589. The Authority notes that all new facilities investment to occur in the third access arrangement period will still have to be assessed as to whether it satisfies the new facilities investment test, either at the time of revisions to the access arrangement for the fourth access arrangement period or at the time of any application by Western Power under provisions of sections 6.71 and 6.72 of the Access Code.

Inventory

590. Western Power proposes including an amount relating to inventory assets in the opening capital base for the third access arrangement period and making an annual adjustment to the capital base reflecting changes to the stock of inventory. Western Power states that the inclusion of inventory is to "recover the financing costs associated with efficiently holding these assets for users of covered services".

591. The Authority has considered this proposal in paragraphs 424 to 425 as part of its assessment of the opening capital base. For the reasons stated in those paragraphs, the Authority has determined that Western Power's proposed adjustment to include the costs of inventory in the capital base should not be allowed.

174 Amended transmission and distribution expenditure is allocated a portion of amended corporate operating expenditure based on the ratio of Western Power's proposed allocation of corporate expenditure to transmission and distribution in each year of the regulatory period.

175 Amended transmission and distribution expenditure is allocated a portion of amended real input escalation based on Western Power's proposed allocation of transmission and distribution network operating expenditure.

176 Amended transmission and distribution expenditure is allocated portion of amended indirect capital expenditure based on the ratio of Western Power's proposed allocation of these costs.

177 Proposed transmission and distribution expenditure excludes inventory and mid-year timing assumption.

Required Amendment 16

Western Power's proposed adjustment to the capital base for the third access arrangement period for changes to the stock of inventory must be removed.

Mid-Year Timing Assumption

592. Western Power has proposed to adopt a mid-year timing assumption for capital expenditure to establish the opening capital base and the notional capital base throughout the third access arrangement period. Western Power states that the 'mid-year timing is appropriate to simulate the impact of incurring new facilities investment throughout the year'.[178] It also notes the timing of its "summer ready" program requires a significant portion of its investment program to be completed by December each year.

593. Western Power states that, to be consistent with the target revenue end-of-year cash flow timing assumption, capital expenditure added to the capital base effectively on a mid-year basis must be adjusted to an end-of-year cash flow. It notes this has the effect of capitalising the first six months of costs and provides for them to be recovered over the life of the assets. It has achieved this by adjusting the new facilities investment in each year for the time value of money for six months by applying the following factor to new facilities investment and adding this amount to the capital base. Western Power notes that its proposed revision is in line with the approach currently used by the AER in its 'post-tax revenue model'.

594. The Authority has considered this proposal in paragraphs 435 to 447 as part of its assessment of the opening capital base. For the reasons stated in those paragraphs the Authority has determined that Western Power's proposed adjustment to adopt a mid-year timing assumption for capital expenditure in the notional capital base throughout the third access arrangement period should not be allowed.

Required Amendment 17

The proposed revised access arrangement must be amended to remove any amounts in relation to a mid-year timing assumption.

Depreciation

595. Under section 6.70 of the Access Code, an access arrangement must include a specification of the method by which depreciation allowances for assets of the capital base are calculated, assumptions as to asset lives and the circumstances in which the depreciation of a network asset may be accelerated.

[178] Revised Access Arrangement Information, Section 10.2.6, p. 243.

596. Western Power's proposed method and assumptions for calculation of depreciation allowances are set out in clauses 5.3.1 to 5.3.6 of the proposed access arrangement revisions.

597. In determination of total costs for the third access arrangement period, Western Power calculates depreciation allowances using the straight-line method with assumptions of average residual lives of existing assets included in the initial capital base values of the transmission and distribution networks, and total asset lives for new assets introduced to the capital base as new facilities investment. Western Power has maintained the same method of straight-line depreciation but has revised assumptions of asset lives in calculation of depreciation allowances as applied for the second access arrangement period. Western Power has applied different assumptions on the asset lives of transmission SCADA and communications, transmission IT and distribution IT assets.

598. Assumptions of asset lives for the asset categories of the capital base of the transmission and distribution networks are indicated in Table 63.

Table 63 Asset lives applied for calculation of depreciation allowances[179]

Asset category	Assumed asset life (years)		
	Existing assets at 30 June 2006	New Assets 1 July 2006 to 30 June 2012	New assets from 1 July 2012
Transmission			
Cables	38.1	55	55
Steel towers	41.3	60	60
Wood poles	20.9	45	45
Metering	26.1	40	40
Transformers	25.5	50	50
Reactors	27.0	50	50
Capacitors	23.1	40	40
Circuit breakers	28.2	50	50
SCADA & communications	11.4	34.15	*11*
IT	4.2	16.85	*6*
Other non-network assets	12.0	16.85	16.85
Land and easements	Not applicable	Not applicable	Not applicable
Distribution			
Wooden pole lines	14.5	41	41
Underground cables	36.9	60	60
Transformers	16.9	35	35
Switchgear	13.5	35	35
Street lighting	1.2	20	20
Meters and services	9.2	25	25
IT	9.8	10.16	*6*
SCADA & communications	10.2	10.16	10.16
Other non-network assets	11.3	10.16	10.16
Land and easements	Not applicable	Not applicable	Not applicable

179 Revised Access Arrangement Supplementary Information, Revenue Model

599. The Authority has considered the revised asset lives for these assets and considers that the revised asset lives are reasonable, except for transmission SCADA & Communications. Based on advice from its technical adviser,[180] the Authority considers that 11 years would be realistic if this only related to SCADA master station equipment. However, this asset category includes fibre optic, control cables and remote terminal equipment which the Authority's technical adviser considers should last much longer. The Authority considers that 20 years would be a reasonable weighted average life for this asset class, consistent with the requirements of section 6.70 of the Access Code.

Required Amendment 18

Western Power's revised access arrangement must be amended to reflect a 20 year economic life for depreciation purposes for transmission SCADA and communications.

600. At clause 5.3.4 of the proposed access arrangement revisions, Western Power indicates that accelerated depreciation will be applied to distribution assets that will be decommissioned as a result of the SUPP undertaken by Western Power on behalf of the Western Australian Government. This principle of accelerated depreciation is unchanged from the current access arrangement. The Authority is satisfied with the level of accelerated depreciation for the decommissioned assets as a result of the SUPP.

Table 64 Valuation of accelerated depreciation for the third access arrangement period (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Transmission	0	0	0	0	0
Distribution					
Wooden pole lines	-2.6	-0.3	0	0	0
Transformers	-0.7	-0.1	0	0	0
Switchgear	-0.2	0.0	0	0	0
Total distribution	-3.4	-0.5	0	0	0
Total	**-3.4**	**-0.5**	**0**	**0**	**0**

601. The Authority's technical adviser has noted that Western Power has not included accelerated depreciation in relation to wooden poles or meters that are replaced. Whilst many of these assets will have reached the end of their useful life and already be fully depreciated, GBA considers there will be instances of some such assets not being fully depreciated. The consequence of this is that the cost of those assets will continue to be recovered over the notional life of the asset, and therefore included in future charges, rather than being written off immediately and included in current charges.

602. The Authority requires Western Power to establish the value of any redundant assets included in its current asset base and to include accelerated depreciation to fully write them off.

180 16 March 2012, GBA email correspondence.

Required Amendment 19

Western Power must establish the value of any redundant assets included in its notional capital base for the third access arrangement period and include accelerated depreciation to fully write them off.

Notional Capital Base Values for the Third Access Arrangement Period

603. The Authority has calculated revised values of the notional capital base for the third access arrangement period in accordance with the Authority's determinations under this Draft Decision on whether the forecast of new facilities investment may, under section 6.50 of the Access Code, be taken into account in determination of total costs and target revenue.

604. The revised notional capital base at the end of the third access arrangement period (30 June 2017) for the transmission network of $3,473.1 million compares with a value of $4,209.8 million proposed by Western Power (in dollar values of 30 June 2012).

605. The revised notional capital base at the end of the third access arrangement period (30 June 2017) for the distribution network of $5,588.5 million compares with a value of $6,205.0 million proposed by Western Power (in dollar values of 30 June 2012).

606. The calculation of the revised capital base values is shown in Table 65 and Table 66 below. Equity raising costs are discussed in paragraphs 942 to 949.

Table 65 Authority's revised notional capital base values for the transmission network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening asset value	2,593.2	2,781.8	3,041.0	3,139.2	3,256.6
New facilities investment[181]	273.8	350.5	199.6	223.4	271.0
Inventory	0.0	0.0	0.0	0.0	0.0
Depreciation	(86.4)	(93.9)	(102.4)	(107.8)	(113.8)
Accelerated depreciation	0.0	0.0	0.0	0.0	0.0
Equity raising costs	1.2	2.6	1.0	1.7	3.4
Closing asset base	2,781.8	3,041.0	3,139.2	3,256.6	3,417.2

181 New facilities investment excluded capital contributions.

Table 66 Authority's revised notional capital base values for the distribution network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening asset value	3,932.0	4,247.2	4,618.0	4,971.4	5,290.3
New facilities investment[182]	513.0	583.2	587.1	556.0	559.0
Inventory	0.0	0.0	0.0	0.0	0.0
Depreciation	(197.1)	(215.3)	(236.7)	(239.1)	(251.0)
Accelerated depreciation	(3.4)	(0.5)	0.0	0.0	0.0
Equity raising costs	2.9	3.4	3.0	1.9	0.9
Closing asset base	4,247.2	4,618.0	4,971.4	5,290.3	5,599.1

182 New facilities investment excluded capital contributions.

Return on Regulated Capital Base

Regulatory Requirements

Section 6.4

608. *The price control in an access arrangement must have the objectives of:*

    a) *giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*

        i) *an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.*

609. On 22 April 2010 the Authority issued a notice advising that its preferred Weighted Average Cost of Capital (**WACC**) Methodology published on 25 February 2005, had expired and hence no longer applied to covered electricity networks under the Access Code. The Authority also advised that it had decided not to issue a new determination on the preferred WACC methodology for covered electricity networks.

610. As a consequence, the WACC has been estimated in a manner consistent with section 6.66 of the Access Code.

Section 6.66

611. The section requires that a WACC proposal:

    a) *must represent an effective means of achieving the Code objective and the objectives in section 6.4; and*

    b) *must be based on an accepted financial model such as the Capital Asset Pricing Model.*

Overall Rate of Return proposed by Western Power

612. For the current access arrangement period, the target revenue was determined in real dollar-value terms. A real pre-tax WACC was applied on the regulatory asset base of the regulated business to derive the return on capital, one component of the target revenue. This WACC value was set by reference to a range of WACC values which were derived from ranges of values determined by the Authority for the input parameters in the capital asset pricing model (**CAPM**) and market observations of risk free rates and costs of debt. The WACC input parameters were based on a 'benchmark' efficient network service provider, consistent with current Australian regulatory practice. Calculating a WACC based on a benchmark efficient network service provider provides greater incentives for regulated providers to pursue efficient funding arrangements. The real pre-tax WACC was set at 7.98 per cent in the current access arrangement.

613. In the proposed revised access arrangement, Western Power has proposed a real pre-tax WACC of 8.82 per cent. This WACC value was derived by Western Power on the advice of its consultants for WACC inputs, using a different method to that adopted by the Authority for the purposes of the current access arrangement.

614. The values of input parameters in the determination of the WACC values for both the current access arrangement and the proposed revised access arrangement are summarised as follows:

Table 67 Approved WACC in the Current Access Arrangement and Western Power's Proposed WACC for the Proposed Access Arrangement

Parameter	Western Power's Approved WACC for AA2[183]	Western Power's Proposal for AA3[184]
Nominal risk free rate of return (%)	5.51	5.4
Inflation rate (%)	2.47	2.7
Real risk free rate (%)	2.97	2.63
Equity beta	0.5 - 0.8	0.9 - 1.1
Market risk premium (%)	5.0 - 7.0	6.5 - 8.0
Debt to total value (%)	60	60
Debt margin (%)	4.205 - 4.315 (including debt raising costs of 0.125%)	3.96 - 4.43 (including debt raising cost of 0.125%)
Effective tax rate (%)	30	30
Value of imputation credits (gamma, %)	57-81	25
Range for the real pre-tax WACC (%)	6.59 - 8.32	8.49 - 10.25
Real pre-tax WACC (%)	**7.98**	**8.82**

615. Western Power established its proposed WACC value on the basis of a nominal risk free rate and a debt margin derived from capital market data over a 20-business day averaging period to 31 May 2011.

616. Western Power has indicated that it will seek an agreement with the Authority on the averaging period or "sampling period" to determine the market-based WACC parameters for the Authority's final decision (such as the estimates of the risk free rate and debt risk premium). Western Power also indicated that the agreed averaging period will be kept confidential until the Authority delivers its final decision.[185] The Authority notes that provision for such an agreement by a regulator exists under the National Electricity Rules (sections 6.5.2(c) and 6A.6.2(c)), but that such an agreement is not contemplated under the Access Code. The Authority will accept this approach consistent with previous decisions.

[183] 2009. Economic Regulation Authority, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 4 December 2009, Table 76, p. 236.

[184] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, Tables 76-8, pp. 247-8.

[185] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 257.

Approach to Estimating the Rate of Return

Western Power's Proposal

617. Western Power proposes that the Rate of Return used in determining the total revenue and reference tariffs for the revisions to the Access Arrangement (AA) be determined as a real, pre-tax weighted average of the returns applicable to debt and equity. Western Power notes that a real pre-tax WACC formulation is appropriate and also consistent with the Authority's preferences and that the formulation meets the Access Code requirements and remains appropriate for calculating the WACC for AA3 for the period from 1 July 2012 to 30 June 2017.

618. In its submission to the public consultation, Western Power noted that a move to a post-tax model would require considerable time to obtain the relevant data, modify the model and test the results. Western Power's view is that a change of this significance would require sufficient notice to enable it to happen and is best left until the next regulatory period.

619. Western Power submitted that its approach to estimating the WACC is based on the following considerations:[186]

- Consultants' reports prepared by Strategic Finance Group (**SFG**) and Ernst & Young (**E&Y**);
- Recent developments in global capital markets with the ongoing high level of volatility in the wake of the global financial crisis and the ongoing uncertainty surrounding sovereign debt in Europe and the United States;
- Examination of recent regulatory WACC decisions made by the Australian Energy Regulator (**AER**) and the decisions of the Australian Competition Tribunal (**ACT**) in related appeals; and
- Adoption of a pre-tax real WACC.

Submissions

620. Among 34 submissions that have been received by the Authority, the following submissions deal with the estimates of the WACC:

- Western Australian Major Energy Users (WAMEU);
- Griffin Power Pty Ltd;
- Synergy;
- Verve Energy;
- Landfill Gas and Power Pty Ltd;
- Alinta Energy (Australia) Pty Ltd;
- Perth Energy;
- Gold Fields Australia Pty Ltd (claiming confidentiality);
- Office of Energy;

[186] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 256.

- Western Australian Local Government Association (WALGA); and
- ERM Power Ltd.

621. WAMEU's submission deals with most of the parameters for the estimates of the WACC. The issues raised in this submission will be addressed separately for each WACC parameter.

622. Some key themes from the submissions from interested parties are summarised below.

- Synergy requests the Authority to consider the proposed WACC in light of Western Power's status as a monopoly state-owned entity, having a lower commercial risk profile and access to lower borrowing costs.
- Verve Energy suggests Western Power's proposed WACC may be excessive given recent global economic developments and in light of the Authority's decision on the revised access arrangement for the DBNGP.
- Griffin Power, Landfill Gas and Power, and ERM Power all consider the credit rating should reflect a WA Government entity rating.
- Alinta considers the rate of return should incentivise the service provider to act in a commercial manner when making investment decisions.
- The Goldfields Esperance Development Commission supports Western Power's proposed WACC noting Western Power's increasing cost pressures and its need for an adequate return on investment.
- Griffin Power, Perth Energy and Landfill Gas and Power supported moving to a post-tax return.

Considerations of the Authority

623. The Authority notes there is a growing precedent that the post-tax form of the WACC being used.

Pre-tax versus post-tax approaches

624. To date, the Authority has used a real pre-tax WACC approach in its regulatory decisions because this method:

- avoided the need to forecast inflation ex ante in setting the overall price path;
- simplified financial modelling; and
- allowed consistency across regulated utilities in Western Australia.

625. Increasingly other regulators are moving to a post-tax WACC, recognising that the use of a pre-tax WACC tends to over-compensate service providers for their tax liabilities (Table 112). The Authority considers that this over compensation does not meet the objectives of the Code, as it does not result in economically efficient pricing.

626. The Authority observes that a number of Australian and foreign regulators adopt a post-tax modelling approach.

- The Queensland Competition Authority and New Zealand Commerce Commission (NZ) currently adopt nominal post-tax modelling.

- The Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER) use a post-tax nominal form of the WACC.
- The Essential Services Commission of Victoria (ESC) has used a post-tax real form of the WACC.
- The Office of Gas and Electricity Markets (UK) and Office of Water and the Water Services Regulatory Authority (UK) currently adopt real post-tax modelling.

627. With the recent decision by the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) to move to a real post-tax WACC, the only remaining regulators using a pre-tax approach are the Independent Competition and Regulatory Commission (ICRC), and the Essential Services Commission of South Australia (ESCOSA). The Authority notes that there is a legislative requirement for ESCOSA to use a pre-tax WACC when determining prices for SA Water.

628. The Authority considers that the use of an explicit post-tax approach allows a regulated entity's effective tax liabilities to be estimated more precisely – overcoming shortcomings with the pre-tax approach – thereby meeting the objectives of the Code. The post-tax approach recognises that:

- pre-tax WACC regulatory method (implicit) 'earnings before tax' tend to differ from actual post-tax method 'earnings before tax', reflecting differences in the respective depreciation schedules, as well as in the tax base itself;
- tax rebates and offsets may need to be incorporated;
- accumulated tax losses and any expected changes in tax treatment can affect the timing of tax liabilities.

629. The alternate method of estimating a pre-tax WACC at effective tax rates is impractical as no publicly available reasonable estimates of benchmark effective taxation rates exist. These would need to be modelled, requiring the same work as modelling taxation liability directly, but would be less transparent in application.

Table 68 Tax treatment in other jurisdictions

Regulator	Form of WACC	Nominal or real tax liability	Accumulated tax losses	Tax rate	Depreciation allowance	Gearing
AER[a]	Nominal post-tax	Nominal	Yes	Statutory	Tax	Benchmark
IPART[b]	Real post-tax (water)	Nominal	Yes	Statutory	Tax	Benchmark
ESC[c]	Real post-tax	Nominal	Yes	Statutory	Tax	Benchmark
ERA (existing)[d]	Real pre-tax	Real	No	Statutory	Regulatory	Benchmark
QCA[e]	Nominal post-tax	Nominal	No	Statutory	Tax	Benchmark
ESCOSA[f]	Real pre-tax	Real	No	Statutory	Regulatory	Benchmark
NZ Commerce Commission[g]	Nominal post-tax	Nominal	Yes, but limited	Statutory	Tax	Benchmark
UK Ofgem[h]	Real post-tax	Nominal		Statutory	Tax	Benchmark for low geared Actual for high geared
UK Ofwat[i]	Real post-tax	Nominal		Statutory	Tax	Benchmark for low geared Actual for high geared

Notes: All regulators allow for dividend imputation

a) Australian Energy Regulator 2010, Amendment : Electricity transmission network service providers Post-tax revenue model handbook, www.aer.gov.au
b) IPART 2011, The incorporation of company tax in pricing determinations: Other industries – Final Decision, www.ipart.nsw.gove.au.
c) Essential Services Commission 2009, Melbourne Metropolitan Water Price Review 2008-09–Final Decision, www.esc.vic.gov.au.
d) Economic Regulation Authority 2012, Revised Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, www.erawa.com.au.
e) Queensland Competition Authority 2010, Gladstone Area Water Board 2010 Investigation of Pricing Practices; Dalrymple Bay Coal Terminal 2010 Draft Access Undertaking, www.qca.com.au.
f) ESCOSA 2009, Metropolitan and Regional Water and Wastewater Pricing Process, www.escosa.com.au.
g) Airport Services Input Methodologies Determination December 2010; Commerce Act (Transpower) Input Methodologies Determination 2010; Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper December 2010.
h) Electricity distribution final price control review: final proposals, 2004
i) Setting price limits for 2010-15: framework and approach, 2009

Source: Authority analysis (but drawing extensively on IPART 2011, *The Incorporation of Company Tax in Pricing Determinations*, www.ipart.nsw.gov.au, p. 10)

630. Accordingly, for this Draft Decision, the Authority requires Western Power to model its tax liabilities explicitly, as a separate ‘building block’, in order to determine the revenue requirement for AA3.

631. Where an overall real post-tax revenue framework is adopted, nominal modelling of the post-tax building block tends to be implemented (refer Table 68). This is because it is not possible to accurately estimate tax liabilities in a real account. In this case, the resulting nominal post-tax estimates of the tax liabilities then may be deflated to real terms using the estimate of future inflation, and incorporated into the real revenue model. This real post-tax model can overcome many of the problems associated with the real pre-tax approach.

632. However, there is no clear precedent for the choice between a real or nominal post tax modelling approach to the overall revenue requirement (Table 68). There are advantages and disadvantages associated with each approach, and the issues are complex. The key issues include:

- the treatment of depreciation in the regulatory accounts;
- alignment of treatment in the regulatory accounts and the tax accounts; and
- how to deal with differences between expected and actual inflation.

The Authority will consider these issues as part of the fourth access arrangement period.

633. The Authority’s view is that there are advantages with remaining with a real revenue modelling framework – which utilises the real post-tax WACC to calculate the Rate of Return. These advantages relate principally to the ability to:

- incorporate a post tax approach which addresses a major shortcoming of the previous approach, thereby meeting the objectives of the Code; and
- retain actual inflation outcomes in the setting of the maximum revenue.

634. For these reasons, the Authority considers that a real post-tax approach, incorporating nominal modelling of the tax liabilities as a separate building block, should be adopted for AA3.

The Post-Tax “Vanilla” WACC Formula:

635. With separate modelling of tax liabilities, the appropriate WACC to apply is the post-tax ‘vanilla’ WACC. The nominal post-tax ‘vanilla’ form of the Weighted Average Cost of Capital (WACC) is expressed below:

$$WACC_{vanilla} = E(R_e) \times \frac{E}{V} + E(R_d) \times \frac{D}{V}¶$$

where:

- $E(R_d)$ is the post-tax expected rate of return on equity – the cost of equity;
- $E(R_e)$ is the pre-tax expected rate of return on debt – the cost of debt;
- E/V is the proportion of equity in the total financing (which comprises equity and debt); and
- D/V is the proportion of debt in the total financing.

636. The real post-tax WACC is obtained by removing expected inflation π_e from the nominal post-tax WACC.

$$WACC_{\text{Real post-tax}} = \frac{\left(1 + WACC_{\text{Nominal post-tax}}\right)}{1 + \pi_e} - 1$$

Nominal Risk Free Rate of Return

Wester Power's Proposal

637. Western Power has adopted the yield on ten-year Commonwealth Government Securities (CGS), reported by the Reserve Bank of Australia (RBA), as a proxy for the nominal risk free rate. Western Power submitted that the approach was accepted by the Authority for the purpose of estimating Western Power's WACC for the current access arrangement, known as AA2, and also for decisions on Western Australia Gas Networks (WAGN) in 2011.

638. Western Power notes that the Authority's adoption of a five-year term for the risk free rate is based on its view that there are strong grounds for matching the term to maturity of debt with the access arrangement period. Western Power, however, is of the view that the maturity of debt issuance is a separate issue to the maturity of the risk free rate used in the CAPM to estimate the cost of equity.

639. In addition, Western Power is of the view that the term of the risk free rate used in the CAPM should be 10 years in order to achieve consistency with:
    - the MRP has been estimated historically (i.e. relative to the 10 year risk free rate);
    - the objective of limiting volatility in the cost of capital allowance (protecting both customers and businesses from this volatility); and
    - the price control objectives set out in section 6.4 of the Access Code, which in effect require that the cost of equity not be underestimated.

640. Western Power proposes a nominal risk free rate of return of 5.40 per cent.[187] Western Power also notes that there are no Commonwealth Government bonds maturing in exactly 10 years. As such, Western Power is of the view that the appropriate nominal risk free rate is estimated by interpolating on a straight line basis between the 15 May 2021 and 15 July 2022 Commonwealth Government bond yields. This is the average of 10-year CGS for the 20-trading day period commencing on 4 May 2011 and ending on 31 May 2011.

Submissions

641. In its submission, WA Major Energy Users submit that the basis for setting a risk free rate for a five-year regulatory period being the average of a relatively few days prior to the publishing a final decision is not really an appropriate assessment. As such, they propose that a longer period such as one or two years should be used as the averaging period for setting the risk free rate.[188]

Considerations of the Authority

642. The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments (i.e. no risk of default). The Commonwealth Government bond is widely used as a proxy for the risk free rate in Australia. CAPM theory does not provide guidance on the appropriate proxy for the risk free rate. In Australia, the current practice of regulators is to average the yield on the indexed 10-year Commonwealth Government bond for a period of 20 trading days as close as feasible before the day the decision is made.

643. However, in its most recent decisions on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (DBNGP), released in 2011, the Authority was of the view that there should be consistency between the terms of the risk free rate and the debt risk premium. In these decisions, the Authority concluded that there are strong grounds for matching the assumption of term to maturity with the regulatory period, which is generally 5 years. A term of the risk free rate which matches the length of the regulatory period of 5 years better reflects the financing strategies of regulated businesses in Australia. The Authority is of the view that the use of a term of 5 years matching the regulatory period will result in correct compensation consistent with the "NPV=0" rule.[189]

644. As a result, in these decisions, the Authority considered the nominal risk free rate of return should be estimated using yields from the 5-year Commonwealth Government bonds reported by the RBA. This conclusion was discussed in detail in both the Draft Decision released in March 2011[190] and Final Decision released in October 2011.[191]

---

[187] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 258.

[188] WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, p. 35.

[189] Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, October 2011, pp. 125-9.

[190] Economic Regulation Authority, 2011, Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, March 2011, pp. 182-7.

[191] Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, October 2011, pp. 125-9.

645. In addition, the Authority has now been using the Bond Yield approach to estimate the debt risk premium for regulated businesses, which will be discussed in the 'Debt Risk Premium" section. The average term to maturity of Australian corporate bonds included in the benchmark sample in the Bond Yield approach used by the Authority, as at 29 February 2012, is 4.66 years.

646. With regard to Western Power's concern about the adoption of the 5-year term to maturity for a nominal risk free rate, as mentioned in paragraph 639 above, each of these three concerns is discussed in turn below.

Consistency with the estimates of the Market Risk Premium (MRP) using historical data on equity return

647. In previous regulatory decisions, the Authority had relied on an estimate of the historical equity risk premium for the period for 1883 – 2010 by Associate Professor Handley in January 2011, together with other pieces of information, to derive the evidence for the forward-looking long-term estimates of the MRP.

648. The Authority is aware that, in his studies for the AER, Handley has used a 10-year term to maturity for the Commonwealth Government bonds in the estimates of the MRP using historical data on equity risk premium. This is a point of contention that Western Power raised in its submission, with regard to inconsistency between the adoption of the 5-year term to maturity for a nominal risk free rate of return and the estimates of the MRP.

649. However, the Authority considers that this claim by Western Power is no longer valid. The Authority has recently conducted its analysis with regard to the estimates of the historical equity risk premium, using a 5-year term to maturity for the Commonwealth Government bonds. Details are discussed in the "Market Risk Premium" section.

Consistency with the objective of limiting volatility in the cost of capital allowance

650. The cost of capital, or the rate of return on capital, is determined to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services. As such, any estimate of the WACC should reflect the volatility of the WACC parameters, particularly the market-based WACC parameters such as the nominal risk free rate of return, the debt risk premium and expected inflation at or around the period in which the decision is to be made.

651. As a result, the Authority does not agree with Western Power's submission that using a 10-year term for the nominal risk free rate will limit the volatility of the cost of capital allowance. The Authority is of the view that the principle under the regulatory regime is that the best forward looking estimate of the cost of capital should be used at the time a decision is made. This approach is likely to deliver the best outcome because the cost of capital will reflect the current conditions in the market for funds.

Consistency with the price control objectives set out in section 6.4 of the Access Code

652. Section 6.4 of the Access Code states that a return on investment must be commensurate with the commercial risks involved. This means that Western Power is allowed to earn a return which is consistent with the level of risk involved in providing its references services.

653. As previously discussed, the Authority is of the view that the use of a term of 5 years, matching the regulatory period, will result in appropriate compensation for the regulated businesses and is consistent with the requirement of Section 6.4 of the Access Code.

Draft Decision

654. The Authority does not approve Western Power's proposal in relation to the calculation of the nominal risk free rate of return using the 10-year term to maturity on the Commonwealth Government bonds.

655. The Authority is of the view that there should be consistency between the terms of the risk free rate and the debt risk premium. More than 50 per cent debt profiles for both a privately owned and government owned networks have the average term of less than five years, as presented in Table 72 and Table 73. Bloomberg also indicate that more than 50 per cent of total debt is with term to maturity of less than five years for Australian rated utilities, as presented in Figure 9. In addition, the Authority is of the view that a term of the risk free rate which matches the length of the regulatory period of 5 years better reflects the financing strategies of regulated businesses in Australia.

656. The Authority considers the estimated nominal risk free rate of return should be 3.67 per cent using yields from the 5-year Commonwealth Government bonds reported by the RBA, as at 29 February 2012. Based on an estimated nominal risk free rate of return of 3.67 per cent and an assumed inflation rate of 2.55 per cent, the Authority estimates a real risk free rate of 1.09 per cent.

657. The Authority notes that these values will need to be updated at the time of the Final Decision (or at a time agreed with Western Power), to ensure that they remain commensurate with prevailing market conditions at the time.

Capital Structure

Western Power's Proposal

658. Western Power considers that the gearing level of 60 per cent (debt to total assets) is the efficient capital structure for the AA3.[192] The gearing level under the current Access Arrangement is also 60 per cent.

Submissions

659. WA Major Energy Users argue that an actual gearing of Western Power is more than 80 per cent. As such, the Authority must take note and reflect this gearing into the cost structure.[193]

---

[192] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 259.

[193] WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, pp. 39-40.

Considerations of the Authority

660. The benchmark gearing ratio is considered to be the capital structure of a benchmark efficient utility business. The Authority assumes that the regulated business tends towards the benchmark gearing level in the long-run. As the optimal level of gearing is not directly observable, the 60/40 gearing level is derived from the average of actual gearing levels from a group of comparable firms.[194] The actual proportion of debt and equity for each business is dynamic and depends on a number of business-specific factors.

661. The Authority agrees that Western Power's proposed gearing level of 60 per cent is consistent with the approach taken in relation to the current Access Arrangement and the approach taken in the AER electricity WACC Review, as well as being otherwise consistent with regulatory precedent and with observed levels of gearing of Australian electricity and pipeline companies.

Draft Decision

662. The Authority approves Western Power's proposal that the appropriate debt to total assets ratio (gearing level) is 60 per cent and the equity to total assets ratio is 40 per cent.

Market Risk Premium

Western Power's Proposal

663. Western Power submits that a reasonable estimate of the market risk premium (MRP) falls between 6.5 per cent and 8 per cent.[195] Western Power also states that the proposed range is consistent with the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved and current capital market conditions.

Submissions

664. In its submission, WA Major Energy Users submits that the value of the MRP of 6 per cent that regulators have historically used is appropriate, rather than determine that there has been a quantum shift in the MRP.[196]

Considerations of the Authority

665. In previous decisions, the Authority was of the view that it is appropriate to consider a wide range of evidence for the forward-looking long-term estimates of the MRP, including:

- an estimate of the historical equity risk premium for the period for 1883 – 2010 by Associate Professor Handley in January 2011;[197]

---

[194] Australian Energy Regulator, May 2009, Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters.

[195] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 259.

[196] WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, p. 41.

- surveys of market risk practice; and
- the Authority's approach and other Australian regulators' current practice.

666. The Authority follows the same approach to determine the appropriate estimate of the MRP for Western Power's proposed access arrangement.

The Method of Using Historical Data on Equity Risk Premium

667. The market risk premium is the required return, over and above the risk free rate, on a fully diversified portfolio of assets.

668. It is the current practice of regulators across Australia to estimate the MRP using historical data on equity premia.

669. Australian regulators have consistently applied a MRP of 6 per cent in their decisions, except for the AER's decisions after its review of WACC parameters released in May 2009. It is noted that a MRP of 6 per cent was first adopted in Australia by the ACCC[198] and the Victorian Office of the Regulator General. A MRP range of 4.5-7.5 per cent was derived on the basis of consultant work prepared by Professor Davies at the University of Melbourne, where the upper bound of this range was based on historical estimates and the lower bound was based on cash flow measures.[199] As such, the mid-point of that range (6 per cent) was adopted. Subsequently, Australian regulators have consistently applied a MRP of 6.0 per cent, which is estimated using historical data on equity premia.

670. In its previous regulatory decisions with regard to the estimates of the MRP using historical equity risk premium, the Authority relied on the studies by Associate Professor Handley at the University of Melbourne prepared for the AER. In these studies, Handley used the observed yields on 10-year Commonwealth Government bonds as the proxy for the nominal risk free rate.

671. As previously discussed, the Authority has adopted the 5-year term to maturity for the risk free rate. As such, for consistency purpose, the Authority considers that it is more appropriate to adopt a 5-year term to maturity for the estimates of the MRP using historical equity risk premia.

672. The Authority is aware that the observed yields on 5-year Commonwealth Government bonds have become available since July 1968. This was also confirmed by Handley in his report to the AER in 2008.[200]

673. The Authority has constructed a data set of more than 40 years, from 1968 to 2011, inclusive.

---

[197] Handley, 2011, "An estimate of the historical equity risk premium for the period for 1883 – 2010", A report for the Australian Energy Regulator, January 2011.

[198] ACCC, Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System – Access arrangement by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Western Transmission System – Access arrangement by Victorian Energy Networks Corporation for the Principal Transmission System, Final Decision, 6 October 1998.

[199] ORG, Access arrangements – Multinet Energy Pty Ltd and Multinet (Assets) Pty Ltd – Westar (Gas) Pty Ltd and Westar (Assets) Pty Ltd – Stratus (Gas) Pty Ltd and Stratus Networks (Assets) Pty Ltd , Final decision, October 1998.

[200] Handley, 2008, "A Note on the Historical Equity Risk Premium", A report for the Australian Energy Regulator, 17 October 2008, p. 4.

674. An equity market index was used as a proxy for the market return. This data is obtained using a Bloomberg terminal.[201] The series was based on the All Ordinaries Accumulation Index, a value weighted index made up of the largest 500 companies as measured by the market caps that are listed on the Australian Stock Exchange. This index captures a market return comprising dividends and capital gains.

675. For consistency, the yearly index value is the arithmetic average of the daily closing index values during the corresponding December.

676. The estimate of Commonwealth Government bond yields (or the risk free rate) is the yields on 5-year term Treasury Bonds. The risk free proxy series from 1969 to 2011 were collected from the Reserve Bank of Australia website.

677. The MRPs were calculated as the difference between the historical market return and the opening Treasury bond yield. This means that:

$$MRP_t = E_t - Y_{t-1};$$

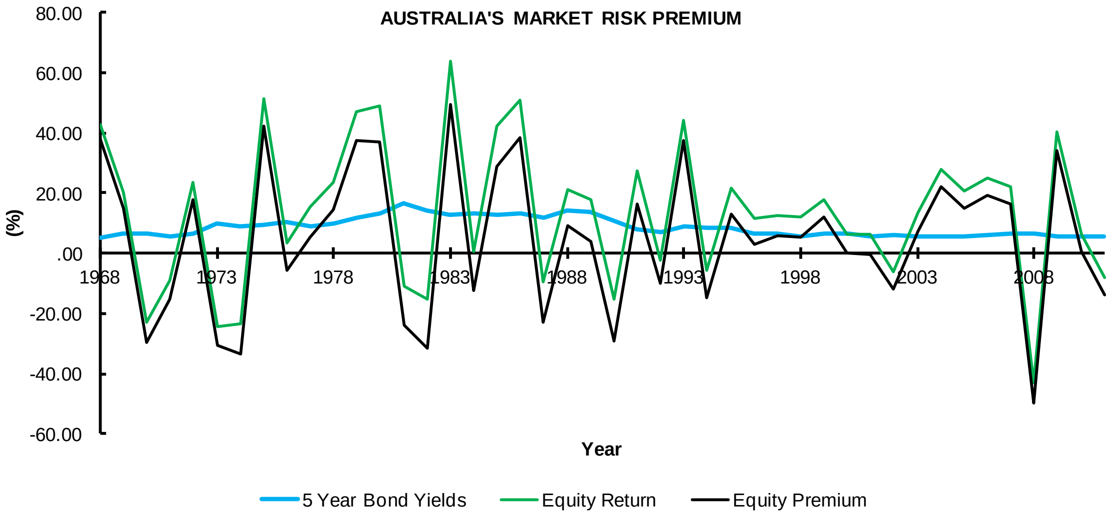
where:

- MRP_t is the market risk premium for year t;
- E_t is the nominal equity return for year t; and

678. - Y_{t-1} is the 5-year Commonwealth Government bond yield for year $(t-1)$.

679. Figure 9 below presents the estimates of Australia's MRP for the period from 1969 to 2011.

Figure 9 Australia's Market Risk Premium, 1968 – 2011, Per cent



Source: RBA, Bloomberg, and Economic Regulation Authority's analysis

[201] The ticker of *ASA30 Index* and the field of *PX_LAST* were used to obtain the data.

680. Table 69 below presents the estimates of Australia's MRP for the period from 1968 to 2011 over different periods.

Table 69 Estimates of Australian Market Risk Premium, 1968 - 2011

Period	No. of years	MRP Per cent	MRP [including imputation credit][202] Per cent
1968 - 2011	44	4.7	5.2
1980 - 2011	32	4.8	5.6
1988 - 2011	24	3.8	5.0

Source: Economic Regulation Authority's analysis

681. The analysis presented in Table 69 supports the Authority's view that the estimate of the MRP using the historical equity risk premia is within the range of 5 to 6 percent.

The Survey Method

682. The Authority also observes that 6.0 per cent is the market risk premium value most commonly used by Australian market practitioners. Surveys of market risk practice show that 47 per cent of market practitioners apply a MRP of 6.0 per cent, while 69 per cent apply a value of 6.0 per cent or less. Only 31 per cent of market practitioners apply values of MRP more than 6.0 per cent.[203] However, the Authority is cautious about relying on this evidence as these surveys preceded the global financial crisis in 2008.

683. Surveys in 2009[204] and 2010[205] show that the average MRP adopted by market practitioners was approximately 6 per cent. These findings are similar to the market surveys prior to the Global Financial Crisis.[206]

684. In addition, evidence from broker reports indicates that the current market practice is to adopt a MRP of approximately 6 per cent. In addition, a recent report from AMP Capital Investors indicates that its forward-looking MRP is lower than 6 per cent.[207]

---

[202] Assumed values of imputation credit were obtained from AER, the Weighted Average Cost of Capital Review, Final Decision, May 2009, Table 7.2, p. 209.

[203] G. Truong, G. Partington and M. Peat, 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p. 155.

[204] Fernandez and Del Campo, Market Risk Premium used by Professors in 2008: A Survey with 1400 Answers, IESE Business School Working Paper, WP-796, May 2009, p. 7.

[205] Fernandez and Del Campo, Market Risk Premium Used in 2010 by Analysts and Companies: A Survey with 2400 Answers, IESE Business School, 21 May 2010, p. 4.

[206] For example, see Truong, Partington and Peat (2008), 'Cost of capital estimation and capital budgeting practices in Australia', *Australian Journal of Management*, Vol. 33, No. 1, June 2008, p.155. KPMG (2005), *Cost of Capital – Market Practice in relation to Imputation Credits.* Capital Research (2006), *Telstra's WACC for network ULLS and the ULLS and SSS businesses – Review of reports by Professor Bowman,* Associate Professor Neville Hathaway.

685. Anthony Asher conducted a survey of MRP estimates by a number of Australian actuaries in February 2011. There were 58 respondents. Most of the respondents were associated with Investment and Wealth Management, Insurance, Superannuation and Banking. The study reported that, on average, respondents had about 15 years of experience as actuaries. The survey found that the average MRP expected over the next 12 months was 4.7 per cent, while the average expected over the next ten years was 4.9 per cent. The author noted that the standard deviation of the former estimate is 2.5 per cent, and of the latter 2.0 per cent. In these estimates, franking credits were taken into account.[208]

686. In a recently released article, “Market Risk Premium Used in 56 Countries in 2011: A Survey with 6,014 Answers” by Pablo Fernandez, Javier Aguirreamalloa and Luis Corre from IESE Business School, University of Navarra, the authors provided an analysis of the results of an international survey on the MRP in March and April 2011. Of the 3,998 survey responses that provided an estimate of the MRP, 40 were from Australia and offered an estimate of the MRP for the Australian equity market. The average of these 40 estimates of the Australian MRP was 5.8. Of the 40 responses received for Australia, 15 were from academics, 21 from analysts and 4 from managers of companies. The average of the estimates of the MRP received from academics was 6.2, from analysts 5.4 and from managers 6.5. While the overall average for Australia was 5.8, the median was significantly lower, at 5.2.[209]

Current Practice by Australian Regulators

687. The Authority has consistently adopted a point estimate of the MRP of 6 per cent in its regulatory decisions.[210] For the current access arrangement for Western Power, the Authority was of the view that the range of the MRP was between 5 per cent and 7 per cent, and that the point estimate of 6 per cent, being the average of the two, was appropriate.[211]

688. The AER adopted a MRP of 6 per cent in 2011 in its final decision on Envestra’s access arrangement proposal for the South Australian gas network, released in February 2011.[212]

689. IPART has used a market risk premium range of 5.5 per cent to 6.5 per cent in its recent determinations, such as for metropolitan and outer metropolitan bus services in December 2009, the CityRail determination, and recent determinations on prices charged by Sydney Catchment Authority and Hunter Water. IPART argues that deriving the MRP from a long-term historical time series remains appropriate. IPART also considers that relying on a long-term historical time series adequately takes into account any impact on excess returns of recent market events, such as the global financial crisis.

---

[207] Oliver, Shane, 2011, *Why are Australian shares lagging? Will it continue?* AMP Capital Investors, January 2011, p. 2.

[208] Asher, A. (2011), “Equity Risk Premium Survey: Results and Comments”, *Actuary Australia,* 161, July 2011, pp. 13-15.

[209] The Australian Competition and Consumer Commission, 2011, *Network,* Issue 41, September 2011, p. 11.

[210] For example, see The Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, 31 October 2011, p. 137.

[211] The Economic Regulation Authority, 2009, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 4 December 2009, p. 236.

[212] Australian Energy Regulator, June 2011, Final Decision, Envestra Ltd. – Access Arrangement proposal for the Qld gas network, pp. 44-46.

690. The Queensland Competition Authority has also used 6.0 per cent for the MRP in its draft determination for Queensland Rail in December 2009. QCA argued that it did not lower the MRP when the market conditions at the time led some stakeholders to seek a reduction; therefore increasing the MRP now would be inconsistent with its past practice that sets the MRP at a level to encourage investment over the medium term, and not in response to short-term market fluctuations.

Recent Developments in the Australian Financial Market

691. The Authority is aware of current developments in the financial markets both in Australia and overseas. However, the Authority is of the view that the investors' expectations of the long-run forward-looking MRP is unlikely to change frequently in response to any developments in the financial markets in the short term.

692. It is noted that, one of the approaches the Authority has adopted to estimate the MRP is to use a historical return on equity premia. In that analysis, the Authority has considered a much longer period in which the MRP is derived, ranging from 20 years to 40 years. In addition, also in the same analysis, the term to maturity of a risk-free rate of 5-year is adopted.

Draft Decision

693. After considering all available information and the aforementioned analyses, the Authority is of the view that a MRP of 6 per cent is appropriate. This is consistent with the view of some other Australian regulators, including the AER, IPART and QCA, that this is the best estimate of a forward-looking long-term MRP.

694. The Authority considers that a reasonable point estimate for the MRP is 6 per cent.

Effective Tax Rate

Western Power's Proposal

695. Western Power proposes to adopt the current corporate tax rate of 30 per cent to calculate a pre-tax WACC.[213] The corporate tax rate under the current Access Arrangement is also 30 per cent.

Submissions

696. The Authority did not receive any public submissions regarding the proposed corporate tax rate.

Considerations of the Authority

697. Consistent with Australian taxation law, the Authority has applied the current corporate tax rate of 30 per cent to calculate the tax liabilities within the post-tax building block that contributes to the determination of the revenue requirement.

[213] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 260.

698. The resulting effective tax rate is an explicit endogenous outcome of the post-tax building block (refer paragraph 628).

Draft Decision

699. The Authority approves the use of a corporate tax rate of 30 per cent.

Value of Imputation Credits (Gamma)

Western Power's Proposal

700. Western Power proposes an estimate of gamma of 0.25. This proposal was based on a recent decision by the Australian Competition Tribunal (**ACT**) with regard to the estimate of gamma.

Submissions

701. In its submission, WA Major Energy Users proposes to adopt the gamma of 0.25 determined by the ACT but acknowledge that imputation at the level of 0.25 hardly justifies the Australian government retaining imputation for dividends.

Considerations of the Authority

702. A full imputation tax system for companies has been adopted in Australia since 1 July 1987. While Australia and New Zealand have full imputation tax systems (which are discussed below), many other countries have a partial imputation system, where only partial credit is given for the company tax.

703. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities is best viewed as personal income tax collected at the company level. With the full imputation tax system in Australia, the company tax (corporate income tax) is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

704. The actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of (i) the franking credits that are created by the firm and that are distributed (*the payout ratio*, F); and (ii) the value that the investor attaches to the credit (*theta*), which depends on the investor's tax circumstances (that is, their marginal tax rate). As these will differ across investors, the value of franking credits may be between nil and full value (i.e. a gamma value between zero and one).

$$\gamma = F \times \theta$$

705. The above equation to estimate gamma is generally known as the Officer framework. In his advice to the AER,[214] Handley advised that the Officer

[214] Handley, J., *Further Issues relating to the Estimation of Gamma,* a report prepared for the Australian Energy Regulator, October 2010, pp. 3-6.

framework for estimating gamma is a theoretical simplification which only applies in a perpetuity setting. Handley also agreed that the alternative Monkhouse approach, which is briefly discussed below, provides a closer approximation to reality.

706. The Monkhouse approach (1996) relaxes the assumption of the payout ratio of imputation credits of 1.0. This approach incorporates the time value loss associated with the retention of imputation credits into the definition of gamma:

$$\gamma = F \times \theta + (1 - F) \times \psi$$

- where F is the distribution or payout ratio;
- θ (theta) is the per dollar value of a distributed credit;
- γ (gamma) is the value of a dollar of imputation credits; and
- ψ (psi) is the per dollar value of a retained imputation credit, where $\psi < 0$ due to time value loss associated with retaining credits.

707. From the above Monkhouse approach, the value of imputation credits (gamma) may be interpreted as a weighted average of the value of a distributed credit and the value of a retained credit. The difference between the value of a distributed credit θ and the value of a retained credit ψ is time value loss only, which in turn depends on the expected retention period, τ (tau) and the appropriate discount rate, δ (delta).

708. However, Handley is of the view that using the Monkhouse approach requires an estimate of the value of a retained imputation credit. He notes that it is unnecessary to adopt a more complicated (albeit more realistic) approach than the Officer framework, given the inherent imprecision in the value of theta.

709. A low value of gamma implies that shareholders do not obtain much relief from corporate taxation through imputation credits and therefore require a higher pre-tax income in order to justify investment.

710. The Authority is aware that the value of gamma was considered by the Australian Competition Tribunal in a recent application by Energex Limited[215] and this decision on the value of gamma has been taken into consideration, in relation to the estimates of the payout ratio and the value of theta, for the Authority's draft decision on the proposed Access Arrangement.

Payout Ratio (F)

711. The Authority is aware of the recent decision by the Tribunal with regard to the payout ratio. The Authority considers that the range of the payout ratio of 70 per cent to 100 per cent is appropriate given the information currently available to the Authority.

[215] Australian Competition Tribunal, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4.

712. The Authority considers that an estimate of the payout ratio of 70 per cent is appropriate based on the empirical evidence currently available. This estimate is consistent with the Tribunal's decision with regard to the value of the payout ratio.[216] The Authority is of the view that existing evidence still supports the use of a range of 70 per cent and 100 per cent for payout ratio. The lower bound of 70 per cent is from empirical evidence and the upper bound is from the view that imputation credit does have a value. However, in the absence of any new evidence and in the interest of regulatory certainty so as to not distort future investment decisions, the Authority has no basis to depart from the findings of the Tribunal in respect of gamma.

713. In conclusion, the Authority's decision is to adopt the payout ratio of 70 per cent in this draft decision on the Western Power's proposed Access Arrangement.

Theta (θ)

714. The dividend drop-off study is the only approach used by the Tribunal to determine the value of theta. The Tribunal considered that redemption rate studies should only be used as a check on the reasonableness of the market value of imputation credits as estimated from dividend drop-off studies. On this basis, the Authority may consider further evidence on the estimate of theta using redemption rate studies in the future when this sort of study has been refined on economically justifiable grounds (such as a consideration of any time value loss between when imputation credits are distributed and when they are redeemed, which is currently not taken into account in redemption rate studies).

715. The Authority maintains its position in its previous regulatory decision[217] that dividend drop-off studies are affected by estimation issues, including multicollinearity and heteroscedasticity. As such, estimates of theta using dividend drop-off studies are inherently imprecise. As a result, the Authority is of the view that a range of evidence should be considered where available.

716. For the same reason as discussed in paragraph 711 with regard to the estimate of the payout ratio, the Authority considers that, in the absence of any reliable new evidence and in the interest of regulatory certainty, it should apply a value of theta which is consistent with the Tribunal's decision. As such, the Authority uses SFG's 2011 dividend drop off study, which estimated a value of theta of 0.35, in this draft decision.[218]

---

[216] Australian Competition Tribunal, Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010), paragraph 4.

[217] For example, see Economic Regulation Authority, 2011, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natuarl Gas Pipeline, 31 October 2011, p. 140.

[218] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 38.

Gamma (γ)

717. Based on an estimate of the payout ratio of imputation credits of 70 per cent, together with an estimate of theta of 0.35, the Authority concludes that a reasonable value of gamma, for the purpose of the Authority's draft decision on Western Power's proposed Access Arrangement, is 0.25 (or 25 per cent). The estimate of gamma of 0.25 is consistent with the Tribunal's recent decision on gamma in *Energex Limited*.[219]

Draft Decision

718. The Authority approves Western Power's proposal in relation to gamma of 0.25.

Benchmark Credit Rating

Western Power's Proposal

719. Western Power proposes the adoption of a BBB+ credit rating assumption for a benchmark efficient firm. Western Power submits that this benchmark credit rating was adopted by the Authority and the AER.[220]

Submissions

720. In its submission, ERM submits that the appropriate credit rating for Western Power should be that of the WA State Government rather than a benchmark against corporate bond rates as this better reflects the level of risk faced by holders of debt against WA Treasury Corporation (WATC).[221] Griffin Power has the same view on the issue.

721. Landfill Gas and Power submits that it is not appropriate to create a fiction in which Western Power is considered to borrow from the private banks and the interest payment is determined by its credit rating. Landfill Gas and Power also argues that there is no justification for charging consumers more than is necessary to service debt.[222]

722. Perth Energy submits that a risk of using a benchmark cost of debt is to over compensate Western Power for the cost of borrowing. As such, Perth Energy proposes that the actual cost of debt obtained from WATC should be used as the cost of debt for Western Power.[223]

---

[219] Australian Competition Tribunal, Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011), paragraph 42.

[220] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 261.

[221] ERM Power Ltd, Submission to the Economic Regulation Authority on the Issues Paper on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, December 2011, section 4.2.2.

[222] Landfill Gas and Power, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, December 2011, p. 5.

[223] Perth Energy, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, December 2011, p. 5.

723. WA Major Energy Users argue using the benchmark credit rating, and hence the benchmark cost of debt, for that government-owned businesses does not reflect reality and is without justification. WA Major Emery Users also argue that efficient debt provision should result in the debt being provided at the lowest possible cost and not at a rate that exceeds the actual costs incurred.[224]

724. In its submission, Office of Energy notes that although WATC debt can be obtained using a State government credit rating of AAA, this does not necessarily reflect the risk faced by Western Power as a separate organisation. In addition, a lower rate of return for Western Power may result in a reduction of the Government's ability to fund required network investment and/or to fund other government priorities such as health and education. The Office of Energy also submits that if the WACC is set too low for Western Power, there will be a disincentive for investment and this in turn may impact on service standards. This may also create the potential for future price shocks due to underinvestment.[225]

Considerations of the Authority

725. The current approach to estimating the required rate of return or the WACC for Western Power's proposed access arrangement is to adopt the benchmark framework which is widely used by other Australian regulators. In this benchmark approach, the benchmark credit rating of BBB+ is used. The WACC parameters, such as the equity beta, gearing level, debt risk premium and others, are derived in such a way as to make additional provision in the utilities' cost of capital, to ensure regulatory certainty and to allow for regulatory errors.

726. Australian regulators have tended to use a target credit rating of BBB+ for the benchmark rate of return for their regulated energy businesses. However, due to a limited number of credit ratings of BBB+ for Australian energy firms in the Australian financial market, regulators tend to combine the credit rating of BBB/BBB+ as the benchmark credit rating.

727. In its Draft Decision on the WACC Review released in December 2008, the AER considered a number of approaches to estimate the credit rating, including median credit ratings, simple average credit ratings and OLS regressions. The AER examined data from 2002 to 2008 and found that:[226]

- private electricity businesses had a median credit rating of A-;
- gas networks had a median credit rating of BBB;
- private energy networks had a median credit rating of BBB+;
- government networks had a median credit rating of AA; and
- energy networks had a median credit rating of A-.

---

224 WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, p. 36.

225 Office of Energy, Submission on the Issue Paper on Western Power's Proposed Amendments to its Access Arrangement for the Third Regulatory Period, December 2011, pp. 1-3.

226 Australian Energy Regulator, December 2008, *Explanatory Statement, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 273-83.

728. In its WACC Review in 2009, the AER was of the view that the most appropriate approaches to determining the credit rating of a benchmark efficient network service provider are the "median credit ratings" of sample businesses, and the "best comparators".[227]

729. As a consequence, the AER proposed an increase in the target credit rating used in the estimation of the debt margin, from BBB+ to A-. The AER argued that there is sufficient evidence to increase the benchmark credit rating from BBB+ to A-. The AER based its analysis on:

- the S&P's ratings process, which indicates that qualitative factors in the regulated utilities ratings process result in credit ratings higher than BBB; and
- the quantitative analysis of credit ratings of a sample of utility issued debt which was considered by the AER.

730. However, in its Final Decision released in May 2009, the AER changed its view from the Draft Decision on the benchmark credit rating. The AER noted that:[228]

> "The AER observes that these different techniques provide a range of credit ratings from BBB+ to A-. The AER considers there is ***more evidence to support a credit rating of A-*** than there is to support a credit rating of BBB." [emphasis added].

731. Notwithstanding this, the AER noted that, after considering the submissions it received on its Draft Decision, it was not persuaded at that time that the previously adopted credit rating of BBB+ should be departed from.

[227] Australian Energy Regulator, May 2009, Final Decision*, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 273-83.

[228] Australian Energy Regulator, May 2009, Final Decision*, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* p. 389.

Table 70 Comparison of Different Samples (2002-2008)

Measure	Energy Networks	Government Energy Networks	Private Energy Networks	Private Electricity Networks
Median Credit Rating (Excluding hybrids)	A-	AA	BBB	A-
Median Credit Rating (Hybrids businesses)	A-	AA	BBB+	A-
Number of businesses (Excluding hybrids)	7-10	1-4	5-10	3-5
Number of businesses (Hybrids businesses)	11-15	3-6	7-12	6-8
Government networks (%)	31	81	10	14
Private electricity (%)	41	15	54	77
Electricity (%)	68	83	61	87

Source: AER, December 2008, Table 9.4, page 270.

732. The AER's analysis (as shown in Table 70) demonstrated that the median credit rating remained constant, irrespective of the period selected between 2002 and 2008. Further, it is clear that the median credit rating is A- for both the private electricity sample and the energy businesses in the sample.

733. The Authority's Final Decision in relation to Western Power's proposed Access Arrangement in December 2009 noted that the AER applied a credit rating of BBB+ in its WACC review in 2009, which took into account capital market evidence that would support a credit rating assumption in the range of BBB+ to A-. However, the Authority was required to apply a credit rating of BBB+ from its WACC review on 25 February 2005, which applied until 25 February 2010 for the assessment of Western Power's AA2.[229] As such, in its Final Decision in December 2009, the Authority assessed Western Power's proposed WACC on the basis of an assumed credit rating of BBB+.

734. Table 71 below presents an updated credit rating for Australian energy companies as at December 2011.

[229] Economic Regulation Authority, 25 February 2005, *Determination of the preferred methodology for calculating the weighted average cost of capital for covered electricity networks.*

Table 71 Standard & Poor's Credit Rating for Australian Energy Companies, December 2011

Company	Current Rating by S&P	Comments
AGL	A-	
Alinta	BBB	[Discontinued, last on 15/9/04]
Alinta Network	BBB	[Discontinued, last on 15/9/04]
Country Energy	AA-	Aa3 by Moody
DUET	BBB-	
ElectraNet Pty Ltd	BBB	
Energy Australia	*N/A*	
Envestra Ltd	BBB-	
Ergon Energy Corporation	AA	
ETSA Utilities	A-	
Integral Energy	AA-	Aa3 by Moody
GasNet	BBB	
SPI PowerNet	A-	
SP AusNet Group	A-	

Source: Bloomberg

735. The values in Table 71 are sufficiently close comparators to the efficient benchmark network service provider. This was also the AER's view in its final decision on the 2009 WACC Review.[230]

736. The "median credit rating" approach in the AER's WACC Review in 2009 shows that the median credit rating of the sample of Australian energy businesses is A-. This is the same credit rating as for a sample of Australian privately owned electricity businesses.[231]

737. The Authority is informed by the updated analysis that A- is the median credit rating for the sample of close comparators.

738. The Authority is also aware that the stand-alone credit rating for Synergy, an electricity retailer in Western Australia, is A+ by Standard & Poor's in 2010.[232]

739. On the above analyses, the Authority is of the view that the evidence currently available to it indicates that the benchmark credit rating for network service providers as at December 2011 is A-.

---

230 Australian Energy Regulator, May 2009, Final Decision, *Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 380-1.

231 Australian Energy Regulator, December 2008, *Explanatory Statement, Electricity Transmission and Distribution Network Service Providers – Review of the Weighted Average Cost of Capital,* pp. 273-83.

232 Standard & Poor's, Global Credit Portal, RatingsDirect, Sysnergy, 23 September 2010, p. 8.

Relevance to Western Power of the WA State Government Credit Rating

740. The Authority notes that many public submissions state that the appropriate credit rating for Western Power should be the same as the credit rating for the State Government of Western Australia, being AAA as at December 2011. As a consequence, the cost of debt incurred by Western Power is the actual cost of debt charged by WATC.

741. However, the Authority considers that there is no compelling reason to depart from the credit rating for the efficient benchmark network service provider, which is A- as at December 2011, for the following reasons:

- The State Government's credit rating reflects its power to take recourse against its taxpayers. Western Power's cost of debt should reflect the level of risk inherent in their operations. The difference in the cost of debt to Government and Western Power acts as a premium on credit insurance for taxpayers in the event there is a Western Power default. Eliminating this premium through providing debt to the service provider at the State Government rating leaves taxpayers uncompensated against the risk of a default.
- A credit rating established independent of ownership is required to maintain competitive neutrality. Agencies borrowing from the Government should thus face interest rates equal to private sector rates; that is Western Power's cost of debt should not be lowered to reflect the benefit of Government ownership and should instead be commensurate with the risks Western Power would face were it privately owned.
- A credit rating that is inconsistent with market outcomes distorts investment decisions in upstream and downstream markets. Investment decisions made in those markets would be undertaken as a result of artificially low or high prices stemming from an artificial credit rating and lead to inefficient investment.
- A rating that is inconsistent with efficient market outcomes also creates the potential for the network service provider to undertake inefficient levels of capital investment; ie over-investment if the rating is too low. The WACC must accurately reflect the level of risk embodied in the network service provider's operations in order to constrain the potential for inefficient investment.

742. In summary, the Authority is of the view that it is inappropriate to assign the credit rating of AAA for Western Power for the purpose of estimating the cost of capital for this business.

Draft Decision

743. The Authority's decision is based on the assumption that the level of risk faced by electricity transmission and distribution firms is the same across Australia. As such, using the benchmark rate of return will ensure that Western Australian businesses are treated the same as their "directly comparable" businesses from other States of Australia.

744. For the reasons set out above, the Authority does not approve Western Power's proposal in relation to the credit rating of BBB+ and is of the view that the appropriate credit rating for a network service provider is A-.

Debt Risk Premium

Western Power's Proposal

745. Western Power submits its arguments in response to the Authority's Discussion Paper on "Measuring Debt Risk Premium: A Bond-Yield Approach", released in December 2010.[233]

746. Western Power also submits that adopting a borrowing term of less than 10 years will underestimate the debt risk premium applicable to an infrastructure business.[234]

747. Western Power also cites the decision of the Australian Competition Tribunal (ACT) in an appeal from the AER's decision on Jemena Gas Networks to argue that Bloomberg estimates of fair value curves for Australian corporate bonds are widely used and market respected.[235]

748. Western Power proposes that a debt risk premium should be estimated using the following two methods:[236]

- extrapolating the 7-year Bloomberg estimate of the fair value curve using the spread between Bloomberg's 10-year AAA and 7-year AAA fair value curves over the last 20 trading days to 22 June 2010, when these estimates were last available; and
- extrapolating the 7-year Bloomberg estimate of the fair value curve using the spread between 10-year and 7-year Commonwealth Government Securities as a proxy for Bloomberg's AAA rated bonds over the averaging period commencing on 4 May 2011 and ending on 31 May 2011.

749. Using the above two methods to estimate a debt risk premium, Western Power proposes that the estimated debt risk premiums over the period from 4 May 2011 and 31 May 2011 are within the range of 3.83 per cent and 4.30 per cent.[237]

Submissions

750. In its submission, WA Major Energy Users submit that government-owned networks are not in competition with other network providers and are therefore not in competition with other private firms for sourcing debt. As such, adopting the benchmark debt risk premium is simply wrong and does not recognise that the Code requires the network pricing to be efficient.[238]

---

[233] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 262.

[234] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 262.

[235] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[236] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[237] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[238] WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, p. 36.

Considerations of the Authority

751. The Authority considers each of the issues raised in Western Power's submissions in turn below.

Issues in Response to the Authority's Discussion Paper on the Bond-Yield Approach

752. Issues raised by Western Power and other public submissions received in response to the Discussion Paper have been discussed in detail in the Final Decision on Western Australia Gas Networks Pty Ltd Proposed Revised Access Arrangement for the Mid-West and South-West Gas Distribution Systems, released in 28 February 2011.[239]

753. The AER has recently decided to stop using Bloomberg's estimates of the 7-year fair value curve in its decisions released in November 2011.[240] The AER was of the view that Bloomberg's 7-year fair value curve should be excluded from the sample to estimate the debt risk premium, for the following reasons:

- Bloomberg's estimates of fair value curves are derived using a proprietary methodology that is neither transparent nor verifiable. In addition, in a letter from Bloomberg to the AER dated 28 October 2011, Bloomberg stated that estimates of fair value curves are not a predictive source of price information;
- Bloomberg's estimate of the 7-year BBB fair value curve (the longest BBB rated fair value curve currently published) does not currently reflect available market evidence for long-dated bonds, or the stated views of other independent market commentators; and
- Bloomberg's estimate of the 7-year BBB fair value curve does not reflect the prevailing cost of debt for the benchmark Australian corporate bond.

A Borrowing Term of Less than 10 Years

754. The Authority is of the view that there is no evidence to suggest that regulated businesses will seek to issue long term debt as a matter of preference. Instead, the Authority is aware that some regulated businesses issue debts over a period of less than 5 years.

755. The Authority is aware that regulated businesses generally avoid the situation of having a significant proportion of their debt funding maturing in any one year. In doing so, the businesses reduce their refinancing risks, as not all debts will reach maturity in the same year.

756. The Authority has examined the debt profile[241] of energy network businesses in Australia. Data on the debt maturity profiles of relevant energy businesses in Australia was obtained from publicly available 2010 annual reports.[242]

[239] This decision is available at: www.erawa.com.au/3/1076/48/wa_gas_networks_formerly_alintagas_distribution_sy.pm

[240] The Australian Energy Regulator, 2011, Draft Decision, Powerlink Transmission Determination, 2012/13 – 2016/17, November 2011, pp. 218-9.

[241] Debt instruments used for funding requirements include bank loans, debentures, commercial papers, syndicated bank debts, medium term notes and (both secured and unsecured) senior notes. Liquidity

757. Table 72 below shows that, in the sample of privately owned Australian energy networks, 52.5 per cent of total debt instruments have an average term of 5 years or less.

Table 72 Debt Profiles for Privately Owned Energy Network Businesses

Business	Average Term on Debt			Total Amount ($ millions)
	Less than 1 year	1 to 5 years	More than 5 years	
APA Group	250	800	1,368	2,418
ETSA Utilities, SA	495	1,375	2,489	4,359
Envestra	408	905	1,049	2,362
SP Ausnet	1,403	4,042	3,902	9,347
CitiPower and Powercor, VIC	906	2,212	2,769	5,887
Total	**3,462**	**9,334**	**11,577**	**24,373**
Per cent of total (%)	**14.20**	**38.30**	**47.50**	**100.00**

Source: 2010 Annual Reports and Authority's analysis.

758. The Authority is aware that interest rate swap contracts are normally used by privately owned energy networks to exchange floating interest amounts for fixed interest amounts. In doing so, regulated businesses can reduce their floating cash flow risk exposure, which results from floating rates on borrowings. Regulated businesses normally borrow actual or synthetic floating rate debts and then fix the interest rate for the term of the reset period, which is usually 5 years, using interest rate swaps.[243]

759. The Authority also examined the debt profile of government-owned energy networks in Australia. Table 73 below shows that, in the sample of government-owned energy networks in Australia, approximately 44 per cent of total debt instruments have an average term of 5 years or less.

management policies ensure that the energy businesses have diversified portfolios, in terms of maturity and sources, which reduces reliance on any one source of funding in any particular year.

[242] The Authority uses the same sample of businesses that Deloitte used in the advice for the AER on "Refinancing, Debt Markets and Liquidity" in 2008.

[243] The Australian Energy Regulator, 2008, "Explanatory Statement: Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", December 2008, pp 101-109.

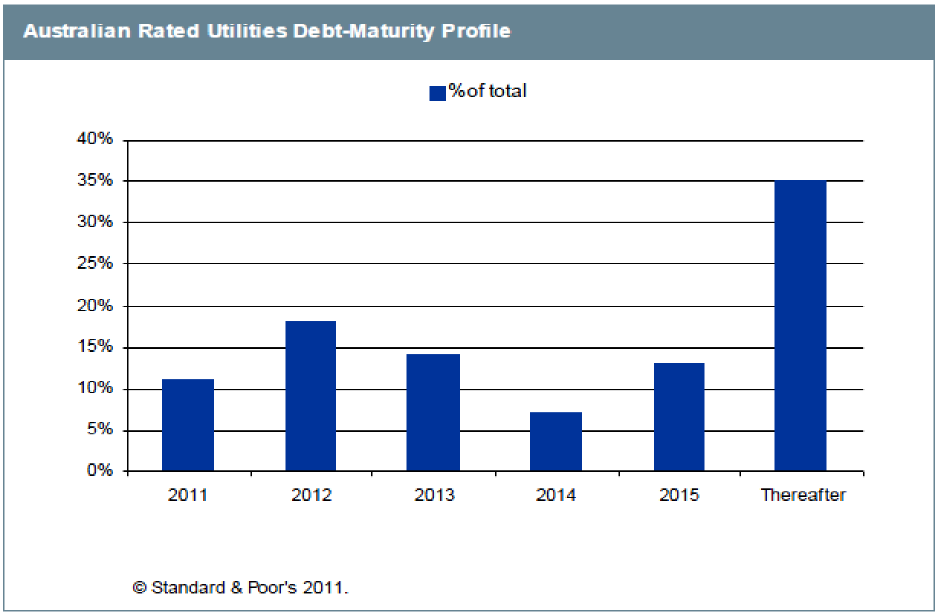
Table 73 Debt Profiles for Government Owned Energy Network Businesses

Business	Average Term on Debt			Total Amount ($ millions)
	Less than 1 year	1 to 5 years	More than 5 years	
Energex, QLD	464	1,129	4,027	5,620
Ergon Energy, QLD	1,273	1,323	3,966	6,562
Powerlink, QLD	283	852	3,439	4,574
Transend Networks, TAS	0	518	0	518
Horizon Power, WA	224	418	776	1,418
Western Power, WA	1,583	2,785	1,344	5,712
TransGrid, NSW	555	1,067	1,753	3,375
Power and Water Corporation, NT	4	134	766	904
Total	**4,386**	**8,226**	**16,071**	**28,683**
Per cent of total (%)	**15.29**	**28.68**	**56.03**	**100.00**

Source: 2010 Annual Reports and Authority's analysis.

760. In addition, Standard and Poor's reports indicate that Australian rated utilities' debt maturity profiles have generally been less than 5 years. Figure 10 presents the findings for the most recent year 2011.

Figure 10 Australian Rated Utilities Debt Maturity Profile



The ACT's Decision

761. It appears that Western Power, in its proposal to adopt Bloomberg's estimate of 7-year BBB fair value curve in the calculation of a debt risk premium, has mistakenly applied the ACT's decision mentioned in paragraph 747 above. The ACT decision was in regard to a decision whether to rely on the CBASpectrum or Bloomberg. Even though the ACT's decision was made and publicly released in 2011, the decision was effectively applied to the issue arising in 2010 before CBASpectrum decided to cease its estimates of fair value curves for all Australian corporate bonds (on 8 September 2010). The cessation of CBASpectrum estimates of fair value curves for Australian corporate bonds was one of the key factors for the Authority developing and releasing its own method of estimating the debt risk premium in December 2010. As a result, the Authority does not see the merit of Western Power's claim with regard to this issue.

762. In addition, in the Authority's Bond-yield approach to estimating a debt risk premium, the Authority considered that Bloomberg's estimates of the fair value curves for Australian corporate bonds across different terms to maturity have increasingly become outdated.

Methods Proposed by Western Power to Estimate the Debt Risk Premium

763. As discussed in its Discussion Paper on "Measuring Debt Risk Premium: A Bond-Yield approach" released in December 2010, the Authority is of the view that:

    - Bloomberg's estimates of fair value curves for BBB+ Australian corporate bonds with longer term to maturity of 7 years and 10 years are problematic; and
    - extrapolation from a 7-year term to a 10-year term is also problematic.

764. In addition, the Authority notes that extrapolation from a 7-year term into a 10-year term is no longer used by any Australian regulator. The AER, in its Draft Decision on Powerlink Transmission Determination released in November 2011, has entirely moved away from Bloomberg's estimates of the fair value curves for Australian corporate bonds.[244] In that decision the AER estimated the bond yields based on a sample of corporate bonds, using a methodology similar to the bond yield approach.

765. As such, the Authority maintains its position that extrapolation of fair value curves from a 7-year term to a 10-year term to derive the debt risk premium is problematic and should not be relied on.

766. The Authority considers that the two methods proposed by Western Power are problematic and that they should not be used to derive the debt risk premium.

Estimating the Debt Risk Premium: A Bond-Yield Approach

767. The Authority is of the view that the bond-yield approach is appropriate for estimating the debt risk premium for Western Power's proposed access arrangement.

[244] The Australian Energy Regulator, 2011, Draft Decision, Powerlink Transmission Determination, 2012/13 – 2016/17, November 2011, pp. 215-9.

768. The Authority has used this approach in its final decisions on Western Australia Gas Networks Access Arrangement released in February 2011 and on the Dampier to Bunbury Natural Gas Pipeline released in October 2011. The Authority proposes to use the same approach for Western Power's access arrangement.

769. Table 74 below summarises a benchmark sample of Australian corporate bonds with the S&P credit rating of A- as at 29 February 2012.

Table 74 A Benchmark Sample of Australian Corporate Bonds with Credit Rating of A- (A Minus) as at 29 February 2012.

Number	Bond	Bloomberg Ticker	Coupon (Per cent)	Maturity
1	AUST & NZ BANKING GROUP	EG230753 Corp	6.50	5/03/2017
2	AUST & NZ BANKING GROUP	EG919776 Corp	7.75	18/10/2017
3	AUST & NZ BANKING GROUP	EJ031088 Corp	7.21	20/06/2022
4	COMMONWEALTH BANK AUST	EG461026 Corp	6.75	25/05/2017
5	POWERCOR AUSTRALIA LLC	EI601137 Corp	4.67	15/01/2022
6	COCA-COLA AMATIL LTD	EI545036 Corp	6.13	30/05/2014
7	COCA-COLA AMATIL LTD	EI963715 Corp	4.88	1/02/2017
8	COCA-COLA AMATIL LTD	EI814473 Corp	5.95	27/09/2021
9	COMMONWEALTH PROP FUND	EI060572 Corp	5.25	11/12/2016
10	MERCEDES-BENZ AUSTRALIA	EI627905 Corp	6.25	11/04/2014
11	MERCEDES-BENZ AUSTRALIA	EI894424 Corp	5.25	12/12/2014
12	ETSA UTILITIES FINANCE	EI619051 Corp	6.75	29/09/2016
13	AUSTRALIA PACIFIC AIRPOR	EI363004 Corp	6.50	25/08/2014
14	AUSTRALIA PACIFIC AIRPOR	EF188672 Corp	6.00	14/12/2015
15	AUSTRALIA PACIFIC AIRPOR	EI363012 Corp	7.00	25/08/2016
16	NATIONAL AUSTRALIA BANK	EG566188 Corp	7.25	21/12/2017
17	STOCKLAND TRUST MANAGEME	EI083701 Corp	8.50	18/02/2015
18	STOCKLAND TRUST MANAGEME	EI494819 Corp	7.50	1/07/2016
19	STOCKLAND TRUST MANAGEME	EI475100 Corp	8.25	25/11/2020
20	SPI ELECTRICITY & GAS	EI193940 Corp	7.50	25/09/2017
21	SPI AUSTRALIA ASSETS PTY	EI340883 Corp	7.00	12/08/2015
22	SPI AUSTRALIA ASSETS PTY	EJ021352 Corp	6.25	21/02/2017
23	TRANSURBAN FINANCE CO PT	EI188381 Corp	7.25	24/03/2014
24	TRANSURBAN FINANCE CMPNY	EF069537 Corp	4.69	10/11/2015
25	VOLKSWAGEN FIN SERV AUST	EI201050 Corp	7.75	31/03/2014
26	VOLKSWAGEN FIN SERV AUST	EI880238 Corp	5.25	21/11/2014
27	VOLKSWAGEN FIN SERV AUST	EI546029 Corp	7.00	28/01/2015

Source: Bloomberg.

770. The Authority considered two scenarios in estimating the debt risk premium using the bond-yield approach:

- Scenario I - a full sample of 27 Australian corporate bonds; and
- Scenario II - a smaller sample excluding all bonds with a less-than-5-year term to maturity.

771. For each of the two scenarios above, the following four weighted average methods were considered:

- a simple average;
- a term-to-maturity weighted average approach;
- an amount-issued weighted average approach; and
- a median approach.

772. As presented in paragraph 656, the Authority considers that the estimated 5-year nominal risk-free rate of return should be 3.67 per cent, for the period until 29 February 2012. This nominal risk free rate is estimated for a 5-year CGS. The same principle is applied to estimate the risk free rate for Australian corporate bonds with more (or less) than 5-year term to maturity. The risk free rate for 5-year CGS must be adjusted to reflect the fact that bonds in the benchmark sample have longer (or shorter) than-5-year term to maturity.

Table 75 Observed Yields, Adjusted Nominal Risk Free Rate, the Debt Risk Premium for A- Australian Corporate Bond as at 29 February 2012.

Number	Issuer	Term to maturity as at 31 January 2012	Observed yields (%)	Risk Free rate (%)	Debt Risk Premium (%)
1	AUST & NZ BANKING GROUP	5.01	5.707%	3.672%	2.035%
2	AUST & NZ BANKING GROUP	5.63	5.752%	3.761%	1.991%
3	AUST & NZ BANKING GROUP	10.31	5.793%	4.117%	1.676%
4	COMMONWEALTH BANK AUST	5.24	5.581%	3.715%	1.867%
5	POWERCOR AUSTRALIA LLC	9.88	5.739%	4.079%	1.660%
6	COCA-COLA AMATIL LTD	2.25	4.451%	3.590%	0.862%
7	COCA-COLA AMATIL LTD	4.92	5.185%	3.667%	1.518%
8	COCA-COLA AMATIL LTD	9.58	5.422%	4.052%	1.369%
9	COMMONWEALTH PROP FUND	4.78	4.706%	3.664%	1.042%
10	MERCEDES-BENZ AUSTRALIA	2.11	5.149%	3.590%	1.559%
11	MERCEDES-BENZ AUSTRALIA	2.78	5.005%	3.583%	1.422%
12	ETSA UTILITIES FINANCE	4.58	5.812%	3.659%	2.152%
13	AUSTRALIA PACIFIC AIRPOR	2.49	5.965%	3.587%	2.378%
14	AUSTRALIA PACIFIC AIRPOR	3.79	6.407%	3.645%	2.762%
15	AUSTRALIA PACIFIC AIRPOR	4.49	6.207%	3.657%	2.550%
16	NATIONAL AUSTRALIA BANK	5.81	5.939%	3.768%	2.170%
17	STOCKLAND TRUST MANAGEME	2.97	6.164%	3.583%	2.581%
18	STOCKLAND TRUST MANAGEME	4.34	6.534%	3.654%	2.880%
19	STOCKLAND TRUST MANAGEME	8.74	7.173%	3.987%	3.186%
20	SPI ELECTRICITY & GAS	5.57	6.136%	3.758%	2.378%
21	SPI AUSTRALIA ASSETS PTY	3.45	5.731%	3.616%	2.114%
22	SPI AUSTRALIA ASSETS PTY	4.98	6.212%	3.669%	2.543%
23	TRANSURBAN FINANCE CO PT	2.07	5.916%	3.590%	2.327%
24	TRANSURBAN FINANCE CMPNY	3.69	5.376%	3.644%	1.732%
25	VOLKSWAGEN FIN SERV AUST	2.09	5.443%	3.590%	1.853%
26	VOLKSWAGEN FIN SERV AUST	2.73	5.472%	3.583%	1.889%
27	VOLKSWAGEN FIN SERV AUST	2.91	5.740%	3.583%	2.157%

773. For example, row 5 from Table 75 shows that the nominal risk free rate for the Powercor bond with 9.88 years to maturity is 4.079 per cent for the 20 trading period

to 29 February 2012.[245] By comparison, the nominal risk free rate for this company, which has been used to estimate the debt risk premium for this bond in the benchmark sample, is higher than the risk-free rate for a 5-year CGS. This is consistent with the finance principle of risk and return trade-off: for longer investments with higher risks, then higher returns are required.

774. The debt risk premiums calculated under the different scenarios and different weighted average methods are summarised in Table 76 below.

Table 76 Debt Risk Premiums under Various Scenarios and Weighted Average Approach, (per cent) as at 29 February 2012

Weighted Average Method	Scenario 1 27 bonds	Scenario 2 8 bonds	Simple Average of all 2 scenarios
Simple Average	2.003%	2.022%	2.012%
Term to Maturity Weighted Average	**2.003%**	**2.052%**	**2.027%**
Amount Issued Weighted Average	1.961%	2.037%	1.999%
Median	2.013%	2.128%	2.070%

Source: Economic Regulation Authority's Analysis

775. Consistent with previous decisions, the Authority is of the view that the term-to-maturity weighted average method is likely to reflect the current conditions in the market for funds. As such, the debt risk premium is calculated as a simple average of the two term-to-maturity weighted average scenarios.

776. As a result, for the 20-day trading period until 29 February 2012 for the Draft Decision for Western Power Access Arrangement, the Authority is of the view that a debt risk premium of 2.027 per cent is reasonable.

Draft Decision

777. The Authority does not approve Western Power's proposal in relation to the methods used to estimate the debt risk premium.

778. The Authority is of the view that the bond-yield approach should be used to estimate the debt risk premium for Western Power's Access Arrangement.

779. For the 20-day trading period until 29 February 2012, the Authority is of the view that a debt risk premium of 2.03 per cent is reasonable and appropriate.

[245] For example, Commonwealth Prop Fund bond will mature on 11 December 2016. As such, the straddle dates which are used to estimate the risk free rate for the Commonwealth Prop Fund bond are 15 February 2017 (for the CGS bond TB120) and 21 July 2017 (for the CGS bond TB135). The two straddle values on these two straddle dates will be interpolated in the same principle with the interpolation process for the nominal risk free rate to estimate the interpolated nominal CGS yield for the Commonwealth Prop Fund bond on the maturity date.

780. The estimate of the debt risk premium will be reviewed for the Final Decision (or at a time agreed with Western Power) to ensure that it reflects the prevailing conditions in the markets for funds at that time.

Debt Issuance Costs

Western Power's proposal

781. Western Power proposes that an allowance of 12.5 basis points per year for debt establishment costs be included in the debt risk premium.[246]

Submissions

782. The Authority did not receive any public submissions in relation to the allowance of debt issuance cost.

Considerations of the Authority

783. The Authority approves Western Power's proposal with regard to an inclusion of 12.5 basis points as the debt issuance costs in the calculation of the cost of debt.

784. Debt raising costs may include underwriting fees, legal fees, company credit rating fees and any other costs incurred in raising debt finance. In practice, regulators across Australia have typically included an allowance of 12.5 basis points for these costs in the cost of debt, as an increment to the debt margin.

785. The current allowance for debt raising costs of 12.5 basis points is based upon a benchmark analysis conducted by the Allen Consulting Group (**ACG**) in 2004.[247] The ACG undertook a study for the ACCC in 2004 on appropriate debt and equity raising costs to be included in costs recognised for the purposes of determining regulated revenues and prices. This study determined debt raising costs based on long-term bond issues, consistent with the assumptions applied in determining the costs of debt for a benchmark regulated entity. Debt raising costs were based on costs associated with Australian international bond issues and for Australian medium term notes sold jointly in Australia and overseas. Estimates of these costs were equivalent to 8 to 10.4 basis points per annum when expressed as an increment to the debt margin.[248] However, for regulatory certainty, Australian regulators have adopted a debt raising cost of 12.5 basis points.

[246] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 263.

[247] Allen Consulting Group, December 2004, Debt and equity raising transaction costs: Final report to ACCC.

[248] Allen Consulting Group, December 2004, Debt and Equity raising transaction costs: Final report to ACCC.

786. The Authority's decision is not only based on the ACG 2004 study, which provided the debt of raising cost of 12.5 basis points, but also on the evidence recently provided to the AER by Associate Professor Handley from the University of Melbourne in April 2010.[249] In this study, Handley considered that the available estimate of the debt raising cost is below 12.5 basis points which has been adopted by Australian economic regulators. The Authority is also of the view that an allowance of 12.5 basis points provides regulatory certainty, given that this amount has been widely used in the past by Australian regulators.

Draft Decision

787. The Authority is of the view that an allowance for debt raising costs of 12.5 basis points is appropriate to be included in the debt risk premium to calculate the total cost of debt for Western Power.

Expected Inflation

Western Power's Proposal

788. Western Power proposes an estimate of the expected inflation based on the geometric mean over the 10-year period of:

- the CPI forecasts from the most recent Statement on Monetary Policy by the RBA; and
- the midpoint of 2.5 per cent for remaining years for which explicit forecasts by the RBA are not available.

789. Using the May 2011 Statement on Monetary Policy, Western Power proposes to adopt the expected inflation rate of 2.70 per cent.[250]

Submissions

790. The Authority did not receive any public submissions in relation to the estimate of expected rates of inflation.

Considerations of the Authority

791. Subject to the following discussion, the Authority accepts Western Power's proposed method for calculating the forecast rate of inflation but does not approve the use of a 10-year term to maturity.

792. Western Power's proposed method calculates the expected inflation rate as the geometric mean of the RBA's inflation forecasts. The Authority is of the view that this method is widely used by Australian regulators and, as such, the Authority accepts the use of this method to calculate the expected inflation rate.

---

[249] Handley, J., April 2010, *A Note on the Completion Method*, Report prepared for the Australian Energy Regulator.

[250] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, pp. 263-4.

793. However, the Authority considers that the term used should be 5 years, which is consistent with the term used to calculate the nominal risk free rate.

794. The Authority has adopted the same method as Western Power. However, the expected rate of inflation has been calculated as a geometric mean of inflation forecasts by the RBA for the next two years and the mid-point estimate of the RBA's long-term inflation forecasts of 2.5 per cent for the remaining *three* years (rather than for the remaining eight years, as used by Western Power). The forecasts which the Authority has relied on for its calculations in this Draft Decision are from the Reserve Bank of Australia's February 2012 *Statement on Monetary Policy*:[251]

- 1.75 per cent for the year to June 2012;
- 3.25 per cent for the year to June 2013;
- 2.75 per cent for the year to June 2014; and
- 2.50 per cent (being a mid-point estimate of the Reserve Bank of Australia's long term inflation forecasts) for each year from June 2015.

795. Using the above forecasts, the Authority has calculated the forecast inflation rate for this Draft Decision of 2.55 per cent.

Draft Decision

796. The Authority does not approve Western Power's proposal in relation to the estimate of the expected inflation of 2.70 per cent.

797. The Authority is of the view that the expected inflation should be calculated based on a 5-year term.

798. The expected inflation of 2.55 per cent is adopted in this Draft Decision. This figure will need to be updated in the Final Decision.

Equity Beta

Western Power's Proposal

799. On the basis of SFG's advice, Western Power submits that two things determine the value of equity beta for a particular firm:

- first, the type of business that the firm operates; and
- second, the amount of financial leverage (gearing) employed by the firm.

800. Western Power also submits that transmission and distribution companies have business activities that are below-average risk, but that their financial leverage is much higher than average, so that the two components of equity beta operate in different directions and will tend to offset one another.

[251] Reserve Bank of Australia, November 2011, *Statement on Monetary Policy*, available at http://www.rba.gov.au/publications/smp/2011/nov/pdf/1111.pdf p. 66.

801. As a result, Western Power proposes that the appropriate *a priori* expectation of the equity beta for transmission and distribution companies such as Western Power is no different from that of the average firm, which is 1.0.[252]

802. As the submission from Western Power is based on the advice of its consultant, SFG, the Authority considers that it is best to respond directly to SFG's advice.

803. The key arguments put forward in SFG's advice to Western Power can be summarised as below.

804. First, an appropriate default equity beta estimate is 1.0. SFG argues that there is no reason for an *a priori* view that the equity beta for an electricity transmission or distribution firm is less than one.

805. Second, the regulatory estimate of equity beta of 0.8 which has been adopted by the Authority and the AER is statistically unreliable.

806. Third, the regulatory estimate of equity beta of 0.8 is commercially implausible, because:

- the approach on which the estimate of 0.8 is based produces implausible estimates over time;
- the required return on unlevered equity cannot be lower than the required return on debt;
- the required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms; and
- for non-resident investors the implied return on levered equity is materially lower than the implied return on debt.

807. Fourth, SFG submits that a New Facilities Investment Test (**NFIT**) under the Code requires the regulator to perform an *ex post* assessment of the efficiency of capital expenditure before new investment can be included in the asset base. As such, there is a risk for Western Power that some capital expenditure will be disallowed. SFG argues that comparable companies regulated under the National Electricity Rules (**NER**) face no such risks.

808. Western Power's second consultant on the issue, Ernst & Young, submits that the requirement to undertake an *ex post* assessment of capital expenditure, and the fact that the Authority has previously exercised this provision in the way that it has, means that investors are exposed to a significant risk that invested capital may not be recovered. Ernst & Young submits that there is evidence to suggest that this is systematic risk, and as such should be compensated. As a result, Ernst & Young proposes that the equity beta for Western Power should be above 0.8.

[252] Western Power, 2011, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, pp. 263-4.

Submissions

809. In its submission, WA Major Energy Users submit that Morningstar calculations for the beta of the Utilities sector currently is 0.76 compared to the ASX200 as a whole of 1.08. They also argue that, over the past decade, the utilities index has outperformed the ASX200 by an average of 20 per cent, which is where it currently stands.[253]

810. WA Major Energy Users also argue that using NFIT as evidence that Western Power has a higher equity risk than businesses under the National Electricity Rules is wrong. It is because there is a similar requirement for new facilities investment to be demonstrably prudent.[254]

811. Perth Energy submits that all standard form contracts with Western Power provide the utility with the ability to retain a zero-commercial risk approach to dealing with its clients, the access users. As such, the estimate of the equity beta for Western Power must reflect this zero-risk business.[255]

Considerations of the Authority

812. The Authority considers each of the issues raised by Western Power and its consultants in turn below.

A Priori View that the Equity Beta for an Electricity Transmission or Distribution Firm is 1.0

813. SFG submits that the business activities of regulated electricity network distribution and transmission businesses have less systematic risk than average, however, these businesses have much higher financial leverage than the average firm (assumed gearing of 60 per cent for regulated businesses versus gearing of 30 per cent for the average firm).

814. SFG argues that the two effects operate in different directions and that there is no compelling *a priori* reason to suggest which of these effects should dominate the other.

815. Consequently, SFG submits that the appropriate *a priori* expectation is that the equity beta for these regulated businesses is no different from that of the average firm, which is 1.0.[256]

816. The Authority notes this argument was raised in the AER WACC review in 2008/2009.

---

[253] WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, p. 42.

[254] WA Major Energy Users, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, November 2011, p. 42.

[255] Perth Energy, Submission on Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network, December 2011.

[256] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, pp. 11-12.

817. The Authority considers that it is generally accepted that the business risks faced by regulated electricity network distribution and transmission businesses are lower than those of the average firm. Western Power and SFG agree on this point.

818. The Authority also agrees that the assumed gearing level of 60 per cent for regulated electricity network distribution and transmission businesses is higher than that of the average firm. However, the Authority does not agree that the financial risk of the regulated businesses is higher than that of the average firm, for reasons discussed below. This means that the Authority does not agree that regulated businesses face higher exposure to financial risk than the average business due to their higher gearing.

819. The Authority agrees with the AER's view that, unlike the unregulated businesses, the cost of debt, including the debt risk premium and the risk free rate for regulated businesses, is based on prevailing market conditions at the time of the regulatory decisions.[257] The Authority is of the view that this "pass-through" nature of borrowing costs is likely to reduce exposure to financial risk faced by regulated businesses.

820. Overall, the Authority agrees that, with regard to regulated electricity network distribution and transmission businesses, a lower business risk results in a lower equity beta compared with the market. Also, the higher gearing level leads to a higher equity beta in comparison with the market. These two effects may act to offset each other. However, the Authority is of the view that it is premature to conclude that the appropriate *a priori* expectation of the equity beta for transmission and distribution businesses is at the market level of one.

821. As the net effect on the equity beta is unclear, the Authority is of the view that conceptual considerations as presented by Western Power and SFG are not a sufficient ground on which to form a conclusive view on the equity beta for transmission and distribution businesses.

822. In conclusion, based on the above reasoning and analysis, the Authority is not convinced by the case put forward by Western Power and SFG, that the appropriate *a priori* expectation of the equity beta for transmission and distribution companies such as Western Power is no different from that of the average firm, which is 1.0. The Authority is of the view that the exposure of regulated electricity network distribution and transmission businesses to business risk and financial risk overall is less than that of the average business or the market. As such, the Authority considers that the equity beta for regulated electricity network distribution and transmission businesses should be less than one.

Regulatory estimate of equity beta of 0.8 is statistically unreliable

823. The Authority notes that this argument is the same issue that SFG submitted to the AER during the WACC Review in 2008.[258]

[257] The Australian Energy Regulator, 2008, "Explanatory Statement: Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", December 2008, pp 193-4.

[258] The Australian Energy Regulator, 2008, "Explanatory Statement: Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", December 2008, p. 187.

824. The AER and its consultant on the issue, Professor Henry from the University of Melbourne, responded to SFG's comments at length in the Final Decision on its WACC Review released in May 2009.[259] The Authority agrees with and adopts the AER and Henry's responses. As such, the Authority is of the view that these arguments should not be reconsidered in this decision.

The approach on which the 0.8 is based produces implausible estimates over time and non-sensible outcomes in other countries

825. SFG submits that one test of the reliability of Professor Henry's approach, which the Authority and the AER have relied on to estimate the equity beta, would be to examine the characteristics of the equity beta estimates produced over a period of time. SFG considers that if the approach produced economically reasonable and relatively stable estimates over time, there would be more confidence in the veracity and reliability of the results, and *vice versa*.[260]

826. SFG submits that it cannot examine the performance of Henry's technique over time due to data unavailability. As such, SFG conducts the analysis for five different industries: commercial services; energy; health equipment; media; and metals mining.[261] Within each industry, SFG selected five comparable firms that had stock return and annual report data available from December 1988 to December 2006, to avoid the effect of the global financial crisis in 2008/09.

827. Based on its analysis, SFG submits that the approach on which the AER's estimate is based produces non-sensible outcomes in other industries.[262]

828. The Authority notes that Henry's approach carefully set out the rationale for the companies to be included in the sample on which the method is applied. The five companies included in Henry's sample represent the best comparator to the efficient benchmark network service provider. In addition, Henry's approach covers the period from 2002 to 2008.

829. The Authority is unclear about SFG's rationale in its selection of industries to confirm the veracity and reliability of Henry's approach to estimating equity beta. SFG does not provide any justification for its selection of the five industries, and the Authority considers that only energy industries are sufficiently linked to the utilities sector in Australia, on which the Henry approach was based.

830. An interesting observation from SFG's results is that, among all findings SFG uses to support its argument (that the approach on which the AER's estimate is based produces non-sensible outcomes in other industries) none of them comes from the energy industry.

---

[259] The Australian Energy Regulator, 2009, Final Decision, "Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters", May 2009, pp. 279-309.

[260] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 26.

[261] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 27.

[262] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 26.

831. As a result, the Authority is of the view that SFG's empirical work on other industries to test the validity of Henry's method is inappropriate and invalid.

832. The Authority has conducted its own analysis using Henry's method with extended data set until 2011. The Authority is informed by this analysis that the estimates of equity beta are quite consistent with Henry's estimates. Further details about this new analysis are discussed below.

The required return on unlevered equity cannot be lower than the required return on debt

833. SFG submits that, the unlevered equity beta (or asset beta) is 0.32[263] is equivalent with an equity beta of 0.8 with the assumed gearing level of 60 per cent. As such, together with the assumed risk free rate of 5 per cent and the MRP of 6 per cent, the return to unlevered equity beta would be 6.9 per cent.[264]

$$\begin{aligned} r_a &= r_f + \beta_a \times MRP \\ &= 5\% + 0.32 \times 6\% = 6.9\% \end{aligned}$$

834. SFG then submits that the debt holder in the benchmark firm requires a return of 8.2 per cent, assuming the debt risk premium associated with a BBB+ credit rating of 3.179 per cent, as concluded in the Authority's Final Decision on WA Gas Networks, released in February 2011.

$$\begin{aligned} r_d &= r_f + DRP \\ &= 5\% + 3.179\% = 8.2\% \end{aligned}$$

835. SFG then concludes that it is impossible for the required return on equity to be lower than the required return on debt in the same firm, because debts have a first-ranking claim over the cash flows of the firm (i.e. debts are entitled to be paid in full before any residual cash flows are paid to the equity holders).[265]

836. The Authority is of the view that SFG is not comparing "apples with apples" in this exercise.

837. First, SFG converts the equity beta of 0.8 into the asset beta of 0.32, with the assumed gearing of 60 per cent for debt.

$$\beta_e = \beta_a \times \left(1 + \frac{D}{E}\right)$$

$$0.8 = 0.32 \times \left(1 + \frac{60}{40}\right)$$

[263] The Authorities view is that this is incorrect; the asset beta should be replaced by the equity beta.

[264] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 28.

[265] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power,* Report prepared for Western Power, July 2011, pp. 28-9.

838. Second, SFG uses the asset beta of 0.32 in lieu of the equity beta in the CAPM to calculate the required rate of return for the unlevered equity beta (i.e. the asset beta) of 6.9 per cent, as presented in paragraph 833. This implies that debt is zero, and that businesses are fully financed by equity.

839. The Authority is of the view that the consequence of using the unlevered equity beta (or asset beta) in the CAPM to derive the required rate of return on equity is that the demand for funds is assumed to be zero. In this hypothetical scenario, there is no business debt because businesses are fully funded by equity. There is only debt issued by the government, with the rate of return known as the risk free rate. The risk free rate compensates investors for inflation risk (i.e. the time value for money) and liquidity risk, but not for any risk premium (the premium paid to investors for bearing a higher level of risk, for example, investing in corporate bonds instead of government bonds). As such, if companies are fully funded by equity, the debt risk premium should be zero, and the cost of debt should be equal to the risk free rate of 5 per cent, which is also lower than the cost of equity.

The required return on equity cannot be materially lower than the return on equity that investors could reasonably expect to receive from comparable firms

840. The Authority notes that SFG has used the same argument, with the same figures as it used in advice provided to WAGN and to the Dampier Bunbury Natural Gas Pipeline (**DBP**). All these arguments are now reproduced in its advice to Western Power with regard to the estimate of equity beta.

841. SFG submits that if investors expect a dividend yield of 9 per cent (on average) from a comparable firm, and if the expected return in the form of capital gains is considered to be in the range of 2.5 per cent and 3.5 per cent per year, then the combined return on equity is in the range of 11.5 per cent and 12.5 per cent.[266]

842. With regard to a dividend yield, a key component in the combined required rate of return, SFG has used dividend forecasts from broker research reports. Table 77 below presents SFG's findings, using research reports' forecasts.

---

[266] Strategic Finance Group, 2011, *An appropriate equity beta estimate for Western Power*, Report prepared for Western Power, July 2011, p. 30.

Table 77 Average Dividend Yield by Firm and Year (Per cent)

Business	Forecasts (Per cent)			Average
	2011	2012	2013	
APA (APA Group)	8.46	8.87	9.30	8.88
DUE (Duet Group)	11.94	12.01	12.03	12.00
ENV (Envestra Limited)	9.56	9.56	9.63	9.59
HDF (Hastings Diversified)	6.36	6.48	6.39	6.41
SKI (Spark Infrastructure)	8.02	8.16	8.35	8.18
SPN (SP Ausnet)	9.00	9.20	9.40	9.20
Average	**8.87**	**9.02**	**9.14**	**9.01**

Source: Table 5, page 30, SFG (2011).

843. Table 77 indicates that the average of the dividend yield forecasts for a sample of six companies above for 2011 is 8.87 per cent.

844. 2011 has now ended. Dividend yields for the above companies were paid in 2011, so they are actual figures and publicly available. The Authority has collected the actual dividend payments for the entire year 2011 for the above companies from the Australian Stock Exchange. The dividend yield is defined as the ratio between total dividend payouts in the year and the closing price of the share as at 31 December 2011.

845. Table 78 compares dividend yields forecast by research reports used by SFG with actual dividend yields for the six companies in 2011.

Table 78 Comparison between forecast and actual dividend yields (Per cent)

Business	Dividend Yields (Per cent) in 2011		
	Forecast	Actual	Difference
APA (APA Group)	8.46	3.99	4.47
DUE (Duet Group)	11.94	10.29	1.65
ENV (Envestra Limited)	9.56	7.96	1.6
HDF (Hastings Diversified)	6.36	4.88	1.48
SKI (Spark Infrastructure)	8.02	8.38	-0.36
SPN (SP Ausnet)	9.00	8.51	0.49
Average	**8.89**	**7.34**	**1.56**

Source: Economic Regulation Authority's analysis

846. The above analysis indicates that the average forecast dividend yield for 2011 of 8.89 per cent for the above sample is overestimated by 1.56 per cent, in comparison with the actual dividend yield of 7.34 per cent. This overestimation is around 18 per cent (1.56 per cent divided by 8.89 per cent) and is significant enough for one to be concerned about the accuracy of such forecasts.

847. As previously indicated in its decisions for WAGN and Dampier to Bunbury Natural Gas Pipeline, the Authority maintains its position that, given the poor record of economic forecasting on which the brokers' research reports are based,[267] the Authority is of the view that it is inappropriate to use the brokers' research reports to derive an estimated cost of equity for any purpose.

New Facility Investment Test

848. Western Power and both of its consultants, SFG and Ernst & Young, submit that NFIT is an *ex post* assessment of the efficiency of capital expenditure before new investment can be included in the capital base. Western Power argues that there is a risk for Western Power that some capital expenditure will be disallowed and as such, no return will be generated from it.

849. Western Power and its consultants submit that this type of risk is systematic in nature. As such, they argue that this risk should be compensated via the equity beta.

850. The Authority notes that the entire WACC framework is developed and applied to the efficient benchmark network service provider. As such, no firm-specific risk will be considered appropriate. In addition, the Authority notes that Western Power may ask for a pre-approval prior to any investment from the Authority. NFIT under the Code is a mechanism to ensure that capital expenditure to be incurred by Western Power is efficient. It is not designed to introduce higher levels of risk for Western Power in comparison with other regulated businesses in Australia.

851. In conclusion, the Authority is of the view that no compensation via equity beta should be allowed with regard to the NFIT.

[267] For example, see Fildes, R. and Makridakis, S. (1995). The impact of empirical accuracy studies on time series analysis and forecasting, *International Statistical Review,* 63, 3, 289-308; and Hendry, D. and Clements, M. (2003). Economic forecasting: some lessons from recent research, *Economic Modelling,* 20, 301-329. For example, Clements and Hendry derive the following nine sources of forecast error as a comprehensive decomposition of deviations between announced forecasts and realised outcomes:

- shifts in the coefficients of deterministic terms;
- shifts in the coefficients of stochastic terms;
- mis-specification of deterministic terms;
- mis-specification of stochastic terms;
- mis-estimation of the coefficients of deterministic terms;
- mis-estimation of the coefficients of stochastic terms;
- mis-measurement of the data;
- changes in the variances of the errors; and
- errors cumulating over the forecast horizon.

Estimates of the equity beta

852. The Authority is of the view that the Sharp-Lintner CAPM is the most widely used form of the CAPM for estimating the cost of equity. The Authority adopts the Sharp-Lintner CAPM to estimate the cost of equity for Western Power's Access Arrangement.

853. The central implication of the CAPM is that the contribution of an asset to the systematic risk of a portfolio of assets (also known as beta risk) is the correct measure of the asset's risk and the only systematic determinant of the asset's return. There are two main components of the CAPM: the market portfolio M, and beta risk β of a portfolio, which correlates the portfolio to the rise and fall of the market.

854. Under the CAPM model, the total risk of an asset can be divided into systematic and non-systematic risk. Systematic risk is a function of broad macroeconomic factors (such as interest rates) that affect all assets and cannot be eliminated by diversification of the businesses asset portfolio. In contrast, non-systematic risk relates to the attributes of a particular asset, where this risk can be managed by portfolio diversification.

855. The most common formulation of the CAPM estimates directly the required return on the equity share of an asset as a linear function of the risk free rate plus a component to reflect the risk premium that investors would require over the risk free rate:

$$R_e = R_f + \beta_e (R_m - R_f)$$

- where R_e is the required rate of return on equity;
- R_f is the risk-free rate;
- β_e is the equity beta that describes how a particular portfolio i will follow the market.

This is defined as:

$\beta_e = \mathrm{cov}(r_i, r_M) / \mathrm{var}(r_M)$ and;

$(R_m - R_f)$ is the market risk premium, MRP.

856. In the CAPM, the equity beta value is a scaling factor applied to the market risk premium to reflect the relative risk to equity funds in the particular firm or activity in question.

857. As stated in paragraph 820, the Authority is of the view that conceptual considerations as presented by Western Power and SFG do not provide sufficient ground to form a conclusive view on the equity beta for transmission and distribution businesses.

858. As a result, the Authority considers that in ascribing a value to the equity beta, primary reliance should be placed on capital market evidence and statistical estimates of beta values, where these are available for comparable businesses.

859. In its 2009 WACC review for electricity transmission and distribution network service providers, the AER, with the assistance of Associate Professor Henry of the University of Melbourne, established a sample of Australian businesses, comprising gas-only network businesses, one electricity-only network business, network businesses active in both electricity and gas, and general utility businesses. Given the limitations of available Australian data, the AER considered that gas network businesses could be considered as reasonable but not perfect comparators to electricity network businesses, given that both industries involve the transportation of energy.[268]

860. Based on empirical work by Henry, the AER concluded that a reasonable range of the equity beta for a gas or electricity distribution network was between 0.4 and 0.7. The AER also considered the need for regulatory certainty and adopting a conservative approach in estimating the equity beta, commensurate with prevailing market conditions and the risks involved in providing reference services. On this basis, the AER considered that a value of 0.8 provides the best estimate of the equity beta arrived at on a reasonable basis for gas and electricity transmission and distribution networks.[269]

861. In the Final Decision for the current access arrangement for Western Power, released in December 2009, the Authority adopted a range for the estimate of equity beta of 0.5 to 0.8. The Authority was of the view that this range was consistent with the analysis presented by the AER in its 2009 WACC Review, based on Henry's empirical study, which suggests an equity beta of between 0.41 and 0.68.

862. The Authority has conducted its own analysis with regard to the estimates of the equity beta. The Authority has used the same approach as adopted by Henry in his study, using an updated data set until October 2011.

863. All data for the Authority's application of Henry's study was sourced from Bloomberg. Data was collected on both a monthly and weekly sampling frequency. Henry advised that a reasonable compromise when faced with the trade-off between the noisy nature of daily data and too few monthly observations to produce reliable estimates of beta was to sample the data at a weekly frequency. Below is a table comparing sample periods in Henry (2009) and the Authority's data set.

268 The main sample consisted of: AGL (2002 to 2005); Alinta (2002 and 2007); Alinta Network Holdings Pty Ltd (2003 to 2006); Country Energy (2002 to 2006); Diversified Utility and Energy Trusts (2003 to 2008); ElectraNet Pty Ltd (2002 to 2008); Energy Australia (2002 to 2006); Envestra Ltd (2002 to 2008); Ergon Energy Corporation (2002 to 2008); ETSA Utilities (2002 to 2008); GasNet Australia (Operations) Pty Ltd (2002 to 2007); Integral Energy (2002 to 2006); SP AusNet Group (2006 to 2008), and SPI PowerNet Pty Ltd (2002 to 2005).

269 See for example: Australian Energy Regulator 2009-10, Final decision: WACC review, May 2009; or Powerlink Transmisison determination, 2012-13 to 2016-17 (Draft Decision, 29 November 2011, p. 33).

Table 79 Henry (2009) and the Authority's (2011) dataset

Henry (2009) Data Sample versus ERA Sample					
	Sample specified in Henry (2009)			Authority sample acquired from Bloomberg	
Company	Source	From	To	From	To
ENV	Datastream	1/01/2002	1/09/2008	4/01/2002	7/10/2011
APA	Datastream	1/01/2002	1/09/2008	4/01/2002	7/10/2011
GAS	Bloomberg	1/01/2002	16/11/2006	4/01/2002	1/12/2006
AAN	Bloomberg	1/01/2002	16/08/2007	4/01/2002	7/09/2007
AGK/AGL	Datastream	1/01/2002	30/10/2006	4/01/2002	27/10/2006
DUE	Datastream	13/08/2004	1/09/2008	13/08/2004	7/10/2011
HDF	Datastream	17/12/2004	1/09/2008	10/12/2004	7/10/2011
SPA/SPN	Datastream	16/12/2005	1/09/2008	16/12/2005	7/10/2011
SKI	Datastream	3/03/2007	1/09/2008	16/12/2005	7/10/2011
ASXAORD/AS30	Datastream	1/01/2002	1/09/2008	4/01/2002	7/10/2011

Source: Economic Regulation Authority's analysis

864. The Authority's empirical study has been conducted in two stages.

- first, for a shorter dataset from 2002 to 2008; and
- second, using an updated dataset from 2002 to 2011.

865. The aim is to consider any significant difference between Henry's (2009) findings and the Authority's (2011) findings, using the same dataset. As presented in Table 79, the Authority obtains data exclusively from Bloomberg, whereas Henry obtained data from both Bloomberg and Datastream.

866. The main purposes for the first stage of the empirical study are to make a "like for like" comparison with Henry's results across this period, and to omit the effect of events associated with the Global Financial Crisis post September 2008.

867. Table 80 and Table 81 below compare the results using monthly samples.

Table 80 Henry (2009) Estimates of Equity Beta, Sampled Monthly

Henry (2009) De-Levered/Relevered estimates of β Australian Companies 2003.09 – 2008.9, Sampled monthly									
	AGK	ENV	APA	GAS	DUE	HDF	SPA	SKI	AAN
$\bar{G}$	0.2719	0.7006	0.5851	0.6617	0.7619	0.4657	0.5673	0.362	0.4133
ω	1.8203	0.7485	1.0372	0.8457	0.5953	1.3357	1.0818	1.5951	1.4667
$\hat{\beta}$	0.6193	0.3908	0.74	0.2829	0.4077	0.8467	0.3665	1.106	1.0749
s.e	0.4019	0.1166	0.2231	0.2694	0.1205	0.3016	0.1685	0.2807	0.4528
$\hat{\beta}_u$	1.4071	0.6193	1.1772	0.8109	0.6438	1.4378	0.6968	1.6563	1.9623
$\hat{\beta}_l$	-0.1685	0.1623	0.3027	-0.2451	0.1717	0.2556	0.0362	0.5558	0.1875
$\tilde{\beta}$	1.1188	0.4202	0.9172	0.4323	0.189	0.6535	0.1869	0.8219	1.0042
s.e	0.4172	0.1169	0.2246	0.2705	0.1249	0.3036	0.1821	0.2896	0.4529
$\tilde{\beta}_u$	1.9365	0.6493	1.3574	0.9626	0.4338	1.2486	0.5439	1.3896	1.8919
$\tilde{\beta}_l$	0.3012	0.1912	0.4771	-0.0979	-0.0558	0.0585	-0.1701	0.2542	0.1165
N	37	60	60	38	48	44	32	18	48

Source: Henry (2009)

Table 81 The Authority (2011) Estimates of Equity Beta, Sampled Monthly

ERA De-Levered/Relevered estimates of β Australian Companies 2003.09 – 2008.9, Sampled monthly									
	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.2339	0.7000	0.5734	0.6258	0.7478	0.3608	0.5751	0.5177	0.3922
ω	1.9153	0.7499	1.0666	0.9356	0.6304	1.5979	1.0623	1.2058	1.5195
$\hat{\beta}$	0.9507	0.4017	0.9131	0.5113	0.4760	0.7150	0.5136	0.6438	1.1594
s.e	0.5211	0.1502	0.2375	0.3265	0.1335	0.3615	0.1868	0.1865	0.5560
$\hat{\beta}_u$	1.9721	0.6961	1.3787	1.1512	0.7376	1.4236	0.8797	1.0094	2.2491
$\hat{\beta}_l$	-0.0706	0.1073	0.4476	-0.1287	0.2144	0.0063	0.1476	0.2783	0.0697
$\tilde{\beta}$	0.2847	0.5718	1.1480	0.5875	0.2746	0.5771	0.4973	0.6479	1.3465
s.e	0.5885	0.1447	0.2403	0.3018	0.2502	0.4872	0.3088	0.1620	0.8937
$\tilde{\beta}_u$	1.4383	0.8554	1.6189	1.1791	0.7651	1.5320	1.1026	0.9655	3.0981
$\tilde{\beta}_l$	-0.8688	0.2882	0.6771	-0.0040	-0.2159	-0.3777	-0.1079	0.3304	-0.4052
N	38	61	61	39	49	45	33	33	48
$\hat{\beta}_i^{ERA} = \hat{\beta}_i^{Henry}$	-0.8247	-0.0934	-0.7761	-0.8477	-0.5666	0.4368	-0.8732	1.6464	-0.1866
$\tilde{\beta}_i^{ERA} = \tilde{\beta}_i^{Henry}$	1.9992	-1.2971	-1.0276	-0.5739	-0.6853	0.2515	-1.7048	0.6008	-0.7557

Source: Economic Regulation Authority's analysis

868. The last two rows of Table 81 show that no estimates based on the same sampling period of monthly observations were statistically different, despite the fact that the Authority exclusively obtained data from Bloomberg.

869. The analysis also shows that estimates of the equity beta using the same method and dataset adopted in Henry (2009) ranged from 0.2746 to 1.3465 with a mean value of 0.6789 and median value of 0.5823. The findings are similar to those reported in Henry (2009) study, as presented in Table 81 above.

870. Table 82 and Table 83 below compare the results using weekly samples.

Table 82 Henry (2009) Estimates of Equity Beta, Sampled Weekly

Henry (2009) De-Levered/Relevered estimates of β Australian Companies 2003.09 – 2008.9, Sampled weekly									
	AGK	ENV	APA	GAS	DUE	HDF	SPA	SKI	AAN
$\bar{G}$	0.2719	0.7006	0.5851	0.6617	0.7619	0.4657	0.5673	0.362	0.4133
ω	1.8203	0.7485	1.0372	0.8457	0.5953	1.3357	1.0818	1.5951	1.4667
$\hat{\beta}$	1.2438	0.2959	0.7612	0.3805	0.355	1.0103	0.2828	0.7865	1.2569
s.e	0.2313	0.0616	0.1186	0.127	0.0676	0.175	0.126	0.302	0.2291
$\hat{\beta}_u$	1.6971	0.4166	0.9937	0.6294	0.4874	1.3534	0.5297	1.3785	1.706
$\hat{\beta}_l$	0.7905	0.1753	0.5287	0.1316	0.2225	0.6673	0.0359	0.1945	0.8079
$\tilde{\beta}$	1.1826	0.1615	0.622	0.3543	0.2519	0.4888	0.2432	1.0375	0.9284
s.e	0.232	0.0621	0.119	0.1284	0.0679	0.1791	0.1264	0.3035	0.2308
$\tilde{\beta}_u$	1.6373	0.2833	0.8554	0.606	0.385	0.8398	0.491	1.6323	1.3809
$\tilde{\beta}_l$	0.728	0.0397	0.3887	0.1027	0.1187	0.1378	-0.0046	0.4427	0.476
N	166	261	261	168	211	193	141	78	207

Source: Henry (2009)

Table 83 The Authority (2011) Estimates of Equity Beta, Sampled Weekly

ERA De-Levered/Relevered estimates of β Australian Companies 2003.09 – 2008.9, Sampled weekly									
	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.2360	0.6996	0.5752	0.6273	0.7482	0.3613	0.5679	0.5150	0.3991
ω	1.9099	0.7511	1.0620	0.9318	0.6296	1.5968	1.0804	1.2124	1.5022
$\hat{\beta}$	1.2994	0.3258	0.7753	0.4217	0.3764	1.1639	0.3231	0.3442	1.2681
s.e	0.2406	0.0656	0.1192	0.1468	0.0716	0.2064	0.1221	0.1574	0.2356
$\hat{\beta}_u$	1.7711	0.4543	1.0089	0.7095	0.5168	1.5685	0.5625	0.6527	1.7297
$\hat{\beta}_l$	0.8278	0.1973	0.5417	0.1339	0.2361	0.7594	0.0837	0.0358	0.8064
$\tilde{\beta}$	1.1706	0.1493	0.6026	0.4240	0.2486	0.5392	0.2622	0.3203	0.9362
s.e	0.2288	0.0539	0.1054	0.1579	0.0750	0.1473	0.1200	0.1234	0.2183
$\tilde{\beta}_u$	1.6191	0.2549	0.8091	0.7335	0.3957	0.8279	0.4975	0.5621	1.3640
$\tilde{\beta}_l$	0.7221	0.0436	0.3960	0.1146	0.1016	0.2505	0.0269	0.0784	0.5084
N	163	265	265	168	215	198	145	145	207
$\hat{\beta}_i^{ERA} = \hat{\beta}_i^{Henry}$	-0.2404	-0.4858	-0.1192	-0.3245	-0.3173	-0.8780	-0.3199	1.4644	-0.0487
$\tilde{\beta}_i^{ERA} = \tilde{\beta}_i^{Henry}$	0.0517	0.1972	0.1634	-0.5429	0.0480	-0.2816	-0.1504	2.3633	-0.0338

Source: Economic Regulation Authority's analysis

871. From Table 83, the Authority notes that 17 of the estimates were not statistically different from Henry's, over the same sampling period using a weekly sample frequency. The SKI estimate using the Least Absolute Deviation (LAD) method was the only one significantly different at the five per cent level.

872. The Authority's analysis using weekly sample indicates that the estimates of the equity beta range from 0.1493 to 1.2994, with a mean value of 0.6084 and median of 0.4229.

873. In the second stage of the empirical study, the data set the Authority sourced for SKI from Bloomberg includes an additional one year and three months' worth of observations.

874. The price data used was the last price provided by the Australian Stock Exchange (**ASX**). The last price was adjusted for changes on the day for all normal and abnormal cash dividend types except those omitted, discontinued, deferred or cancelled.

875. Table 84 and Table 85 below compare the results using the monthly sample.

Table 84 Henry (2009) Estimates of Equity Beta, Sampled Monthly

Henry (2009) De-Levered/Relevered estimates of β Australian Companies 2002.1 – 2008.9, Sampled monthly									
	AGK	ENV	APA	GAS	DUE	HDF	SPA	SKI	AAN
$\bar{G}$	0.3017	0.7079	0.5737	0.6617	0.7619	0.4657	0.5673	0.362	0.4133
ω	1.7457	0.7302	1.0658	0.8457	0.5953	1.3357	1.0818	1.5951	1.4667
$\hat{\beta}$	0.4299	0.2948	0.6212	0.1883	0.4077	0.8467	0.3665	1.106	0.8394
s.e	0.2785	0.0988	0.1898	0.178	0.1205	0.3016	0.1685	0.2807	0.3593
$\hat{\beta}_u$	0.9758	0.4884	0.9932	0.5372	0.6438	1.4378	0.6968	1.6563	1.5437
$\hat{\beta}_l$	-0.116	0.1012	0.2492	-0.1607	0.1717	0.2556	0.0362	0.5558	0.1351
$\tilde{\beta}$	0.1835	0.1524	0.7039	0.3177	0.189	0.6535	0.1869	0.8219	0.8725
s.e	0.2824	0.1002	0.1901	0.1789	0.1249	0.3036	0.1821	0.2896	0.3612
$\tilde{\beta}_u$	0.737	0.3488	1.0765	0.6682	0.4338	1.2486	0.5439	1.3896	1.5805
$\tilde{\beta}_l$	-0.3699	-0.0439	0.3314	-0.0329	-0.0558	0.0585	-0.1701	0.2542	0.1645
N	57	80	80	59	48	44	32	18	68

Source: Henry (2009)

Table 85 The Authority (2011) Estimates of Equity Beta, Sampled Monthly

ERA De-Levered/Relevered estimates of β Australian Companies 2002.1 – 2011.10, Sampled monthly									
	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.2753	0.7181	0.5864	0.6367	0.7620	0.3964	0.6080	0.5019	0.3911
ω	1.8117	0.7049	1.0340	0.9083	0.5950	1.5089	0.9800	1.2452	1.5224
$\hat{\beta}$	0.6993	0.4585	0.6665	0.2588	0.3836	0.0675	0.2591	0.4154	0.8090
s.e	0.3274	0.1180	0.1285	0.2042	0.1033	0.5024	0.1414	0.1703	0.4151
$\hat{\beta}_u$	1.3411	0.6897	0.9182	0.6591	0.5860	1.0523	0.5363	0.7492	1.6227
$\hat{\beta}_l$	0.0575	0.2273	0.4147	-	0.1811	-	-	0.0815	-
$\tilde{\beta}$	0.5013	0.3742	0.6982	0.2354	0.2678	0.4695	0.2561	0.4353	0.9688
s.e	0.3906	0.1081	0.1483	0.2266	0.1324	0.2294	0.1559	0.2198	0.5113
$\tilde{\beta}_u$	1.2669	0.5860	0.9888	0.6797	0.5273	0.9192	0.5616	0.8661	1.9709
$\tilde{\beta}_l$	-	0.1624	0.4076	-	0.0083	0.0198	-	0.0045	-
N	57	116	116	58	85	81	69	69	67
$\hat{\beta}_i^{ERA} = \hat{\beta}_i^{Henry}$	-0.9674	-1.6568	-0.2385	-0.3962	0.2004	2.5835	0.6371	2.4604	0.0846
$\tilde{\beta}_i^{ERA} = \tilde{\beta}_i^{Henry}$	-1.1253	-2.2135	0.0298	0.4598	-0.6310	0.6060	-0.3799	1.3350	-0.2667

Source: Economic Regulation Authority's analysis

876. From its analysis as presented in Table 85, the Authority notes that 15 of the 18 monthly estimates based on the extended sample are not statistically different from those estimated by Henry. The three statistically different estimates included the HDF and SKI estimates using OLS method, and the ENV estimate using LAD method. The Authority notes that the SKI estimate is based on a sample that begins much earlier than Henry's sample, which is likely to be the main source of the difference.

877. The Authority is informed by its analysis that, as presented in Table 85, the estimates of the equity beta range from 0.0675 to 0.9688, with a mean of 0.4569 and median of 0.4253.

878. Table 86 and Table 87 below compare the results.

Table 86 Henry (2009) Estimates of Equity Beta, Sampled Weekly

Henry (2009) De-Levered/Relevered estimates of β Australian Companies 2002.01 – 2008.9, Sampled weekly									
	AGK	ENV	APA	GAS	DUE	HDF	SPA	SKI	AAN
$\bar{G}$	0.3017	0.7079	0.5737	0.6617	0.7619	0.4657	0.5673	0.362	0.4133
ω	1.7457	0.7302	1.0658	0.8457	0.5953	1.3357	1.0818	1.5951	1.4667
$\hat{\beta}$	0.7192	0.2522	0.691	0.3151	0.355	1.0103	0.2828	0.7865	0.9401
s.e	0.1698	0.0526	0.1011	0.0885	0.0676	0.175	0.126	0.302	0.1863
$\hat{\beta}_u$	1.052	0.3553	0.8892	0.4885	0.4874	1.3534	0.5297	1.3785	1.3052
$\hat{\beta}_l$	0.3864	0.1491	0.4928	0.1417	0.2225	0.6673	0.0359	0.1945	0.5749
$\tilde{\beta}$	0.5264	0.1023	0.5976	0.2341	0.2519	0.4888	0.2432	1.0375	0.5974
s.e	0.1703	0.0532	0.1013	0.0888	0.0679	0.1791	0.1264	0.3035	0.1876
$\tilde{\beta}_u$	0.8603	0.2066	0.7962	0.4082	0.385	0.8398	0.491	1.6323	0.965
$\tilde{\beta}_l$	0.1925	-0.002	0.399	0.0601	0.1187	0.1378	-0.0046	0.4427	0.2298
N	252	348	348	255	211	193	141	78	294

Source: Henry (2009)

Table 87 The Authority (2011) Estimates of Equity Beta, Sampled Weekly

ERA De-Levered/Relevered estimates of β Australian Companies 2002.01 – 2011.10, Sampled weekly									
	AGL	ENV	APA	GAS	DUE	HDF	SPN	SKI	AAN
$\bar{G}$	0.277	0.718	0.587	0.637	0.761	0.396	0.607	0.501	0.398
ω	1.806	0.703	1.031	0.905	0.595	1.508	0.980	1.246	1.504
$\hat{\beta}$	0.753	0.359	0.611	0.329	0.317	1.337	0.219	0.492	0.960
s.e	0.177	0.045	0.061	0.100	0.047	0.202	0.067	0.092	0.192
$\hat{\beta}_u$	1.101	0.448	0.731	0.526	0.409	1.734	0.351	0.674	1.336
$\hat{\beta}_l$	0.405	0.271	0.492	0.133	0.225	0.940	0.086	0.310	0.584
$\tilde{\beta}$	0.527	0.312	0.597	0.257	0.262	0.844	0.216	0.344	0.620
s.e	0.198	0.016	0.061	0.088	0.044	0.082	0.071	0.080	0.193
$\tilde{\beta}_u$	0.916	0.345	0.718	0.430	0.348	1.006	0.356	0.502	0.999
$\tilde{\beta}_l$	0.138	0.280	0.476	0.084	0.175	0.683	0.077	0.185	0.241
N	249	509	509	254	373	356	303	303	293
$\hat{\beta}_i^{ERA} = \hat{\beta}_i^{Henry}$	-0.2031	-2.0469	0.7837	-0.1674	0.5497	-1.8712	0.5057	0.9741	-0.1094
$\tilde{\beta}_i^{ERA} = \tilde{\beta}_i^{Henry}$	-0.0053	-3.9580	0.0010	-0.2631	-0.1544	-1.9874	0.2091	2.2845	-0.1244

Source: Economic Regulation Authority's analysis

879. The Authority notes that the weekly sample based on the extended set had 15 of the 18 estimates that were not statistically different from Henry's. The differences between Henry (2009) and the Authority (2011) using the extended dataset include the ENV estimate using both OLS and LAD methods and the SKI estimate using the LAD method at the five per cent level.

880. The Authority is informed by its analysis that the estimates of the equity beta using weekly data range from 0.2168 to 1.3378 with a mean of 0.5204 and median of 0.4261.

881. In conclusion, the Authority's analysis, using the extended dataset to October 2011, can be summarised as below:

- the estimates of the equity beta using monthly data range from 0.0675 to 0.9688, with a mean of 0.4569 and median of 0.4253; and
- the estimates of the equity beta using weekly data range from 0.2168 to 1.3378, with a mean of 0.5204 and median of 0.4261.

882. As a crosscheck, these updated estimates are consistent with the estimates from Henry (2009).

883. The Authority maintains its decision with regard to the estimates of the equity beta adopted in the current access arrangement of 0.5 and 0.8 due to high level of imprecision of the estimate of the equity beta.

884. The Authority is of the view that the point estimate of the equity beta of 0.65, being the average of the lower and upper bounds of the adopted range, is reasonable for the draft decision on Western Power's Access Arrangement for the following reasons:

- it is at the upper end of the empirical estimates by Henry (2009) and the Authority (2011) which indicated that the mean and median values of the equity beta fall within the range of 0.5 to 0.65;
- it is the midpoint of the estimated equity beta adopted in the current access arrangement; and
- the midpoints are taken to reduce the undesired effects of outliers, such that their effect is averaged out.

885. In conclusion, the Authority maintains its decision with regard to the estimates of the equity beta adopted in the current access arrangement of 0.5 and 0.8 due to high level of imprecision of the estimate of the equity beta. The Authority is of the view that the point estimate of the equity beta of 0.65, being the average of the lower and upper bounds of the adopted range, is reasonable for the draft decision on Western Power's Access Arrangement.

Draft Decision on the Rate of Return

886. Based upon the above assessment of each of the CAPM parameters, the point estimates that the Authority considers may reasonably be applied to the parameters of the CAPM and other parameters in the entire WACC framework in estimating the rate of return for Western Power are as shown in Table 88 below.

Table 88 Authority's Required Amendments to Western Power's Proposed Parameter Values for Determination of a Rate of Return as at 29 February 2012 (Per cent)

Parameter	Value (Per cent)
Nominal Risk Free Rate (R_f)	3.67
Real Risk Free Rate (R_f^r)	1.09
Inflation Rate π_e	2.55
Debt Proportion (D)	60
Equity Proportion (E)	40
Cost of Debt: *Debt Risk Premium (DRP) (A-)*	2.027
Cost of Debt: *Debt Issuing Cost (DIC)*	0.125
Cost of Debt: *Risk Margin (RM)*	2.152
Australian Market Risk Premium (MRP)	6.0
Equity Beta (β_e)	0.65
Corporate Tax Rate (T_c)	30
Franking Credit (γ)	25
Nominal Cost of Debt (R_d^n)	5.82
Real Cost of Debt (R_d^r)	3.19
Nominal Pre Tax Cost of Equity $(R_e^{n,\text{pre-tax}})$	9.77[a]
Real Pre Tax Cost of Equity $(R_e^{r,\text{pre-tax}})$	7.04[a]
Nominal Post Tax Cost of Equity $(R_e^{n,\text{post-tax}})$	7.57
Real Post Tax Cost of Equity $(R_e^{r,\text{post-tax}})$	4.89

Note: a) These are the 'backward transformation' estimates that are derived using an assumed 30 per cent effective tax rate. They do not equate to the actual values that may be calculated from the effective tax rates that result from the nominal tax modelling utilised for this Draft Decision.

Source: ERA analysis

Table 89. Estimates of WACC (Per cent)

WACC	Value (Per cent)
Real Pre Tax WACC $\left(WACC_r^{\text{pre-tax}}\right)$	4.73[a]
Nominal Post Tax "Vanilla" WACC $\left(WACC_n^{\text{post-tax}}\right)$	6.52
Real Post Tax "Vanilla" WACC $\left(WACC_r^{\text{post-tax}}\right)$	3.87

Note: a) These are the 'backward transformation' estimates that are derived using an assumed 30 per cent effective tax rate. They do not equate to the actual values that may be calculated from the effective tax rates that result from the nominal tax modelling utilised for this Draft Decision.

Source: ERA analysis

887. The Authority does not approve Western Power's proposal in relation to the rate of return of 8.82 per cent.

888. For the purpose of this Draft Decision, the Authority adopts the point value, being a real post-tax Rate of Return of 3.87 per cent.

Required Amendment 20

Western Power's Proposed Revisions must be amended to adopt a real post-tax rate of return of 3.87 per cent.

Tax on Capital Contributions

Proposed Revisions

889. Western Power has included $240.5 million in its target revenue for net tax costs associated with forecast capital contributions and gifted assets provided by customers.[270] This represents approximately 25 per cent of the forecast capital contributions and gifted assets in AA3.

890. Western Power states that the tax costs arise due to the timing differences in the tax paid on receipt of the capital contributions and gifted assets and the depreciation tax shield provided over the life of the assets. It notes this occurs because capital contributions and gifted assets are treated as revenue by the accounting standards applicable to Western Power - Australian Accounting Standards Board, Interpretation 18 “Transfer of Assets from Customers”, March 2009.

891. Western Power has calculated the tax cost by taking account of:

- circularity arising from the revenue and tax impact of recovering the tax costs;
- dividend imputation franking credits passed through to its shareholder; and
- statutory tax depreciation benefit which offsets the tax costs incurred in later years.

892. Western Power considers circularity arises because a customer’s payment of tax costs is treated as revenue which then increases the value of revenue that is taxed. This in turn requires the payment of additional tax, which further increases the revenue amount and attracts additional tax and so on. Western Power has then offset the benefits arising from dividend imputation franking credits and statutory tax depreciation benefits.

893. Western Power’s calculated capital contribution tax costs are set out in Table 90 below.

Table 90. Western Power’s Proposed Capital Contribution Tax Costs

	2012/13 $m	2013/14 $m	2014/15 $m	2015/16 $m	2016/17 $m	5 year total $m
Transmission tax costs						
Cash contributions	10.6	10.7	10.9	11.0	11.4	54.6
Gifted assets	0	0	0	0	0	0
Total	**10.6**	**10.7**	**10.9**	**11.0**	**11.4**	**54.6**
Distribution tax costs						
Cash contributions	25.5	21.8	19.0	19.3	20.0	105.6
Gifted assets	16.1	16.1	16.1	16.1	16.1	80.5
Total	**41.6**	**37.9**	**35.1**	**35.3**	**36.0**	**185.9**

[270] Revised access arrangement information, Section 12.6, p. 285.

Submissions

894. A number of submissions commented on the tax costs claimed by Western Power and, whilst there was recognition that these are valid costs, considered the costs should be met by the parties who generated the costs.[271] WALGA commented that "the contemplated approach of a revenue levy across the board redistributes the cost away from the user who generates the tax liability and is therefore a hidden cross subsidy and should be avoided". Both Landfill Gas and Power and ERM Power considered that Western Power and the contributing party should negotiate arrangements to deal with these costs.

Considerations of the Authority

895. Western Power considers section 6.4(a)(i) of the Access Code, which allows a service provider to earn revenue to meet the forward-looking and efficient costs of providing covered (regulated) services extends to enabling them to recover the tax costs associated with capital contributions or gifted assets.

896. The Authority notes the comments made by interested parties and agrees that, by including the amount in the target revenue, all network users will have to pay a share of the tax cost on infrastructure they may not benefit from directly.

897. Furthermore, under the treatment of capital contributions as agreed with Western Power at the last access arrangement review, any new facilities investment financed by contributions is not added to the capital base and therefore no depreciation or return is included in the revenue requirement in relation to contributed assets. Correspondingly, contributions received are also not included in the calculation of target revenue. To include taxation costs in relation to contributions in the revenue requirement would be inconsistent with this approach.

The Authority does not consider taxation costs relating to gifted assets or cash contributions should be borne by customers who do not make use of those assets. If Western Power needs to recover such costs, a better approach would be for it to negotiate with the party providing the capital contribution to recover these tax costs.[272] It is understood that the party providing the gifted asset receives a tax benefit as a result of writing off the asset.

Required Amendment 21

No amounts in relation to tax on capital contributions must be included in Target Revenue.

[271] Landfill Gas and Power, ERM Power and WALGA.

[272] ERA, Final Report, Inquiry into Pricing of Recycled Water in Western Australia, 6 February 2009, p. 61.

Return on Working Capital

Access Code Requirements

898. The Access Code does not explicitly contemplate a return on working capital as a cost.

899. The objectives for a price control set out in section 6.4 of the Access Code include the objective of giving the service provider an opportunity to earn an amount of target revenue that meets the forward looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current Access Arrangement

900. The values of target revenue applying under the price control in the current access arrangement include an allowance for a return on working capital.

901. For each of the transmission and distribution networks, a cost of working capital for each year of the current access arrangement was determined as the difference between the implicit cost incurred by Western Power by providing credit to users of services and the implicit benefit to Western Power of receiving credit from suppliers.

902. The requirement for working capital was calculated as the difference between the sum over 45 days of the average daily covered service revenue and the sum over 20 days of the average daily expenses for the year (new facilities investment and non-capital costs). This was based on:

- an assumed revenue lag of 45 days, based on meter reading cycles and payment terms of the electricity transfer access contract; and
- an average expense lead of 20 days on operating and capital expenditure based on:
  - an expense lead of 10 days on labour costs, comprising 18 per cent of costs for the distribution network and 23 per cent of costs for the transmission network;
  - an expense lead of 30 days on direct costs of materials and services, comprising 35 per cent of costs for the distribution network and 63 per cent of costs for the transmission network; and
  - no expense lead on internal costs of materials and services or other costs.

903. The cost of working capital was calculated as the value of working capital at the beginning of each year of the access arrangement period multiplied by the approved pre-tax WACC.

Proposed Revisions

904. Western Power has proposed an allowance for a return on working capital in line with the current access arrangement.[273] The proposed costs of working capital are indicated in Table 91 and Table 92.

Table 91 Proposed Cost of Working Capital – Transmission Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capital)	489.441	519.740	553.323	593.982	655.437
Expenses					
Forecast new facilities investment	352.483	275.872	358.297	523.437	407.650
Forecast non-capital costs	124.996	122.482	132.336	142.406	156.340
Total expenses	477.479	398.353	490.632	665.843	563.990
Working capital requirement					
Receivables (45 days)	60.342	64.077	68.218	73.031	80.807
Creditors (20 days)	-26.163	-21.828	-26.884	-36.385	-30.904
Working capital requirement	34.179	42.250	41.334	36.646	49.904
Return on working capital at WACC = 8.82%	**1.215**	**3.015**	**3.726**	**3.646**	**3.232**

Table 92 Proposed Cost of Working Capital – Distribution Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capital)	1,127.756	1,192.511	1,274.111	1,327.441	1,403.210
Expenses					
Forecast new facilities investment	567.444	650.671	665.611	635.625	642.746
Forecast non-capital costs	371.361	387.391	408.266	420.133	447.854
Total expenses	938.804	1,038.062	1,073.878	1,055.758	1,090.600
Working capital requirement					
Receivables (45 days)	139.038	147.022	157.082	163.210	172.998
Creditors (20 days)	-51.441	-56.880	-58.843	-57.692	-59.759
Working capital requirement	87.597	90.142	98.240	105.518	113.240
Return on working capital at WACC = 8.82%	**5.125**	**7.726**	**7.951**	**8.665**	**9.307**

[273] Revised access arrangement information, Section 12.3, pp. 281-282.

905. Western Power has used the same working capital cycle assumptions as used in the current access arrangement of 45 days for receivables, determined from the meter reading cycles and payment terms of the electricity transfer access contract, and 20 days for creditors, determined from an expense lead of 10 days on labour costs and an expense lead of 30 days on direct costs of materials and services.

Submissions

906. The submission from Landfill Gas and Power considered that only interest on working capital should be passed through to consumers at cost.

907. Submissions from ERM Power and WALGA both rejected the inclusion of a return on working capital in target revenue. They noted that other Australian regulators have previously determined that working capital related issues would only arise where an organisation is not efficiently managed.

Considerations of the Authority

908. "Working capital" refers to a stock of funds that must be maintained by a service provider to pay costs as they fall due. In circumstances where, on average, the costs of providing services are incurred before the revenues from provision of services are received, a stock of working capital may need to be derived from a capital investment in the business. The cost of this stock of working capital (the required return on the capital investment) is a cost to the service provider in operating its business and providing services.

909. The working capital provided for should only reflect the essential items for the conduct of the service provider's business.

Current and Past Application to Western Power

910. In determining proposed allowances for working capital, Western Power has determined a "stock" of working capital that is varied from year to year according to the costs and revenues for each year and assumptions of time periods of credit made available to Western Power by suppliers and credit made available by Western Power to network users. The cost of working capital is determined as a return on the funds invested in the stock of working capital in the same manner as funds invested in the physical assets (capital base) of the network. This has been done in a manner consistent with the allowance for working capital during AA2.

911. While the Authority considered that an allowance for the cost of working capital can reasonably be included in the cost of service during AA2, it noted in its Final Decision and Further Final Decision for AA2 that it was "… aware that regulators in other Australian jurisdictions have questioned whether an allowance for costs of working capital can reasonably be included in the determination of regulated revenues for utility businesses."[274] [275] It continued by noting that it intended to give the matter further consideration.

[274] 4 December 2009, ERA, Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network, p. 252.

[275] 19 January 2010, ERA, Further Final Decision, Proposed Revisions to the Access Arrangement for the South West Interconnected Network, p. 49.

Recent Regulatory Practice

912. The AER does not allow for a return on working capital in its Post Tax Revenue Model (PTRM). The reason for this is that it considers the PTRM already overcompensates service providers. The original basis for this view was a report commissioned by the ACCC in 2002 in relation to working capital for transmission companies.[276] The report endorsed the concept of a timing adjustment being required for the lag in the recovery of operating expenses but also considered the wider issue of all intra-year timing assumptions inherent in the ACCC's total revenue requirement formula. The formula was deemed to over-compensate for intra-year timing in relation to capital costs, by an amount that is likely to exceed the under-compensation for working capital based on operating costs. The report proposed that an allowance should not be included for working capital in order to balance out the discrepancy.

913. Since this work was carried out, the AER has made an adjustment to its cash flow timing assumptions by allowing for mid-year timing in capital expenditure in its PTRM. This amendment further increases the overcompensation already identified.

914. Prior to the AER taking on responsibility for electricity distribution pricing determinations, a mixed approach was taken by the State regulators. The Victorian Essential Service Commission and QCA both took the same approach as the ACCC and rejected allowances for a return on working capital in electricity distribution regulation on the grounds that the service providers are already overcompensated with respect to cash-flow modelling timing. However, IPART and ESCOSA did provide a separate allowance for a return on working capital. IPART took the view that the return on and of assets for fixed assets allowed in the pricing decision was just sufficient to cover these costs and that a separate amount should be made available for working capital. ESCOSA considered "it appropriate to provide an allowance in respect of the cost of financing the operating activities, notwithstanding the overcompensation provided with respect to capital activities.[277] However, ESCOSA did not provide an allowance for working capital for capital activities.

915. The AER is now responsible for all electricity distribution pricing determinations and has adopted the PTRM for determining target revenue. As noted in paragraph 912 above, the PTRM does not allow a separate return on working capital on the basis that it already over compensates service providers in relation to cash flow timing assumptions.

916. The formula the Authority has determined for setting Western Power's target revenue is essentially the same as that used by the AER, with the exception of the mid-year timing assumption for capital expenditure. However, as noted above, the mid-year timing assumption would have just served to increase the over compensation.

917. The Authority has attempted to demonstrate this benefit empirically using the cash flow assumptions Western Power provided with its working capital analysis. Initial results suggest that, in the case of Western Power, there may not be such an over

---

[276] November 2007, AER, Issues Paper: Guidelines, models and schemes for electricity distribution network service providers, p. 11.

[277] ESCOSA, 2005-2010 Electricity Distribution Price Determination – Part A – Statement of Reasons, pp. 122-124.

compensation. Reasons why the result appears to be different from that found by the AER may include:

- differences in the proportions of components of target revenue (e.g. operating expenditure, depreciation or return on the capital base) compared with other service providers;
- specific items such as the TEC and recovery of deferred revenue which are not common to other service providers; and
- differences in cash flow timing assumptions compared with other service providers.

918. The Authority intends to explore this matter further prior to the final decision.

Other factors which reduce the need for a return on working capital

919. In addition to the potential over-compensation in the target revenue formula, the Authority has identified a number of items that provide a benefit to Western Power.

920. Western Power's calculation of working capital ignores the cash contribution payments made to Western Power. Under Western Power's capital contributions policy, these payments must be made to Western Power either up-front or on a periodic basis with interest charged. The amount received by Western Power would be in advance, in some cases it could be considerably in advance, of the required expenditure to build the asset. This could provide a significant benefit to Western Power considering that it has forecast to receive $636 million for transmission and distribution for cash contributions during AA3. This is equivalent to 10.6 per cent of transmission and distribution new facilities investment during the period.

921. In the current regulatory period, Western Power has significantly underspent in operating expenditure and capital expenditure which would have resulted in Western Power receiving a return on working capital above what was actually required. As there is no adjustment mechanism to take account of this, Western Power retains the benefit.

Working capital assumptions

922. Western Power has not demonstrated that its proposed working capital forecasts are efficient as it has determined its working capital requirements based on historic assumptions. The Authority has considered each of the assumptions below.

Debtors

923. The Authority notes that Western Power's assumption for debtor days is in line with its current meter reading cycles and the invoicing and payment terms in the electricity transfer access contract. The majority of meters are read on a bimonthly basis with the remainder read on a monthly basis. The standard terms of the electricity transfer access contract are that an invoice is raised within 14 business days of the month following the meter read and the user is required to pay within 10 business days.

924. However, the Authority notes that Western Power's largest customer, Synergy, endeavours to invoice customers within a few days of the meter being read and requires payment within three weeks of the bill being sent.

Creditors

925. Western Power has based its creditors' payment terms on 10 days for manpower costs and 30 days for other costs, and 0 days for internal costs. As the Authority has included a separate return on inventory (where most internal costs would arise), to avoid double counting the Authority has recalculated the weighted average creditor days based on the information provided by Western Power. This results in 25 days for transmission and 28.5 days for distribution.

Inventory

926. As discussed in paragraphs 424 to 427, Western Power has proposed to include inventory in the capital base. However, the Authority considers it is clearer and more transparent to consider it as part of working capital requirements.

927. Western Power has provided analysis in Appendix D of its proposed revised access arrangement information which it considers demonstrates the efficiency of its forecast level of inventory. Western Power provided two tables in its analysis, one which compares inventory value to works program size and one which compares inventory value to network size by state.

928. As Western Power has only provided aggregate information for each state, the Authority has not been able to verify the analysis provided. However, the Australian averages against which Western Power compares itself have been based on simple averages which do not provide a valid comparison. A weighted average should be used and should be calculated excluding Western Power. This would result in the average measure being lower.

929. On this basis Western Power's performance is worse than the average for other states and worse than all states with the exception of Tasmania for both measures, and Queensland for inventory value to network size.

930. For the purposes of the draft decision, the Authority has used the average level of inventory value to works program size for other Australian service providers to estimate an efficient level of inventory for Western Power. Based on the information provided in Western Power's Appendix D, the Authority has calculated this to be 4 per cent.

Conclusion

931. The Authority considers that working capital is a legitimate business cost but that due consideration should be given to the over-compensation, identified by the AER and others, provided in financial models used by regulators to calculate the total revenue requirement and other factors such as the benefit of receiving capital contributions in advance of expenditure. The Authority will give further consideration to this prior to the final decision. For the purposes of the draft decision, the Authority has included an allowance for working capital with a number of amendments to Western Power's proposal.

932. The gross cost of service, expenses and return on working capital have been amended to reflect the Authority's required amendments elsewhere in this decision.

Table 93 Amended Cost of Working Capital – Transmission Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capita)	297.8	311.8	331.9	343.8	358.3
Expenses					
Forecast capital expenditure	275.0	353.1	200.6	225.2	274.4
Forecast operating costs	100.1	99.2	100.9	103.6	107.5
Total expenses	375.1	452.3	301.5	328.8	381.9
Working capital requirement					
Receivables (45 days)	36.7	38.4	40.9	42.3	44.2
Creditors (28.5 days)	(20.6)	(24.8)	(16.5)	(18.0)	(20.9)
Inventory (4% of capital expenditure)	11.0	14.1	8.0	9.0	11.0
Working capital requirement	27.2	27.8	32.4	33.3	34.2
Return on working capital at WACC = 3.87%	**0.5**	**1.1**	**1.1**	**1.3**	**1.3**
Western Power Proposal	1.2	3.0	3.7	3.6	3.2

Table 94 Amended Cost of Working Capital – Distribution Network (real $ million at 30 June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Gross Cost of Service (excluding working capita)	945.7	974.6	1,015.6	1,030.1	1,066.2
Expenses					
Forecast capital expenditure	515.9	586.6	590.1	557.9	559.8
Forecast operating costs	330.0	331.9	337.4	335.1	346.0
Total expenses	845.9	918.5	927.5	893.1	905.9
Working capital requirement					
Receivables (45 days)	94.3	97.9	102.9	104.3	108.9
Creditors (25 days)	(46.3)	(50.3)	(50.8)	(48.8)	(49.6)
Inventory (4% of capital expenditure)	20.6	23.5	23.6	22.3	22.4
Working capital requirement	68.5	71.0	75.7	77.8	81.7
Return on working capital at WACC =3.87%	**2.3**	**5.7**	**2.8**	**2.9**	**3.0**
Western Power Proposal	5.1	7.7	8.0	8.7	9.3

Required Amendment 22

The amounts included in target revenue for working capital must be amended to the values in Table 93 and Table 94 .

Tax liabilities

Access Code Requirements

933. Clause 6.65 of the Code states that the Authority may determine the preferred method for calculating the WACC in access arrangements.[278,279]

934. The Code states at Section 6.4 that:

> The price control in an access arrangement must have the objectives of:
>
> a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current Access Arrangement

935. Tax liabilities in the current access arrangement are incorporated as an implicit adjustment within the real pre-tax WACC.

Proposed revisions

936. No revisions to the incorporation of tax liabilities within the pre-tax real WACC were proposed by Western Power.

Considerations of the Authority

937. In regulating electricity networks in Western Australia, the Authority determines a revenue requirement that is sufficient to cover the service provider's efficient costs of service. The key elements contributing to the estimated regulated cost of service include depreciation of the regulated capital base, a return on the regulated capital base, the operating costs, and the tax liabilities.

938. As set out above, the Authority has decided to adopt a post-tax real WACC for this Draft Decision.

939. With a post-tax approach, tax liabilities are modelled separately – as an explicit building block within the revenue modelling framework. Accordingly, for this Draft Decision, the Authority has modelled Western Power's tax liabilities in this way, in order to determine the revenue requirement for AA3.

[278] Western Australian Government Gazette 2011, *Electricity Networks Access Code 2004*, Clause 6.65, p. 90.

[279] On 22 April 2010 the Authority issued a notice advising that its preferred Weighted Average Cost of Capital Methodology, published on 25 February 2005, had expired and hence no longer applied to covered electricity networks under the Access Code.

940. To this end, the Authority has:

- calculated a set of taxation accounts that is derived from the regulatory accounts:
  - the initial nominal tax base for AA3 is the closing nominal value of the regulated asset base for 2011-12;
  - expenditure on new assets is brought into taxation asset base at their nominal value in the year of expenditure;
  - any deductions for redundant assets are brought into the taxation asset base at the estimated nominal value in the year of redundancy;
  - a set of taxation accounts is calculated for the transmission business alone, as well as for the whole business;
  - the difference between the amount of tax calculated in the combined tax accounts and the amount of tax calculated in the tax accounts for the transmission business alone is attributed to the cost of service for the distribution business; and
- maintained the debt for taxation purposes at 60 per cent of the estimated taxation asset base:
  - calculated the annual interest payments for taxation purposes from the resulting closing value of the debt account;
  - based the interest rate on a nominal cost of debt that is consistent with the WACC calculation;
- incorporated the cost of raising equity as a cash flow but not assumed any tax deductions (see paragraphs 942 to 949 (on costs of raising equity below) of this Draft Decision);
- carried any estimated tax losses forward;
- depreciated assets in the tax base utilising the prime cost method.

941. The resulting tax liabilities contributing to the maximum annual revenue requirement for the transmission and distribution businesses are set out in Table 4 and Table 5.

Required Amendment 23

The Authority requires that Western Power model its tax liabilities explicitly, as a separate nominal 'building block', applying the method set out in this Draft Decision.

To this end, the Authority requires that Western Power amend the tax liabilities for the purposes of determining its maximum annual revenue requirements to those estimated by the Authority as set out in Table 4 and Table 5.

Costs of raising equity

Access Code Requirements

942. The Code states at Section 6.4 that:

> The price control in an access arrangement must have the objectives of:
>
> a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:
>
> i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current Access Arrangement

943. Equity raising costs were not included as part of the current access arrangement.

Proposed revisions

944. Western Power has not included equity raising costs in the proposed opening capital base at 1 July 2012.

945. However, in line with Section 6.4 (a)(i) of the Code, Western Power proposes to include direct costs of raising equity incurred during AA3:[280]

> We have applied the method for cash flow modelling used by the AER in its recent *Final Decision for Victorian Distributors (2010)* to calculate whether equity raising costs are required for AA3.
>
> Equity raising costs can be classed into two categories: indirect and direct. Direct costs include underwriting, management fees and out of pocket expenses. Indirect costs can include underpricing, where the new equity security is sold at a discount to current market prices. We consider that only direct equity raising costs are relevant to calculating target revenue.
>
> In our modelling, 30% of dividends are assumed to be returned to the business through a dividend reinvestment plan at a cost of 1%. Any further requirement for equity is assumed to come from seasoned equity offerings at a cost of 3%. These assumptions are consistent with the AER's methodology. In keeping with the Australian Competition Tribunal's April 2011 Decision on the value of imputation credits, a distribution rate of 70% is assumed for imputation credits. We have determined that no equity raising costs would be incurred on the basis of these proposed revisions.

Considerations of the Authority

946. The Authority agrees with Western Power that the efficient costs of raising equity may constitute part of the forward-looking costs of providing covered services.

---

280 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 246.

947. The Authority considers that the equity share should be maintained at 40 per cent of the estimated asset base, taking into account that:

- dividends should be assumed to be paid at the benchmark payout ratio of 70 per cent of after-tax profits – consistent with the Authority's WACC analysis;
- retained earnings of 30 per cent of after-tax profits should be assumed to be available at zero cost;
- 25 per cent of dividends should be treated as being reinvested on a 'tick the box' basis, with a zero cost of raising equity applied to these funds;[281] and
- any further required equity should be raised at the Seasoned Equity Offering cost of 3 per cent – with these costs added to the asset base and depreciated over the life of the assets.

948. Appendix 5 provides further detail on the Authority's considerations.

949. The resulting costs of raising equity for the transmission and distribution businesses are set out in Table 65 and Table 66 above.

Required Amendment 24

The Authority requires that Western Power determine the forward looking efficient costs of raising equity according to the method set out in this Draft Decision.

To this end, the Authority requires that Western Power amend the cost of raising equity for the purposes of determining the revenue requirement to those estimated by the Authority as set out in Table 65 and Table 66 .

[281] When investing in shares, where the company has a dividend re-investment plan in place, investors may be offered dividends in cash, or may simply 'tick a box' to have the dividends automatically re-invested.

Adjustments to Target Revenue

Access Code Requirements

950. Section 6.4 of the Access Code provides for the target revenue for an access arrangement period to include certain amounts "carried over" from the previous access arrangement period, including:

- an amount in respect of costs incurred as a result of a force majeure event under sections 6.6 to 6.8 of the Access Code;
- an amount in respect of costs incurred as a result of changes to the Technical Rules, for which no allowance was made in the access arrangement, under sections 6.9 to 6.12 of the Access Code;
- an amount under an investment adjustment mechanism under sections 6.13 to 6.18 of the Access Code;
- an amount under a gain sharing mechanism under sections 6.19 to 6.28 of the Access Code; and
- an amount under a service standards adjustment mechanism under sections 6.29 to 6.37 of the Access Code.

Current Access Arrangement

951. The current access arrangement provides for several revenue adjustment mechanisms to adjust target revenue in the third access arrangement to account for unforeseen events or other cost pass-throughs, over or under-recovery of revenue in preceding years or provide financial incentives to Western Power to be more efficient or perform better. These adjustments occur under the following mechanisms:

- Correction factor – a year-on-year adjustment to allowed revenue to account for under-recovery or over-recovery of revenue under the revenue cap.
- Unforeseen events adjustment – an adjustment to account for costs incurred in the current access arrangement period as a result of force majeure events.
- Technical rule change revenue adjustment – an adjustment to account for costs incurred as a result of changes to the Technical Rules that could not have reasonably been foreseen at the commencement of the current access arrangement period.
- Investment adjustment mechanism – an adjustment to account for differences between forecast and actual costs of certain classes of new facilities investment.
- Gain sharing mechanism – an adjustment to account for the out-performance of the forecast operating expenditure in the current access arrangement.
- Service standards adjustment mechanism – an adjustment to account for any difference between service standard performance and service standard benchmarks in the current access arrangement.
- D-factor – an adjustment to account for any additional operating expenditure incurred as a result of deferring a capital expenditure project, and any additional operating or capital expenditure incurred in relation to demand management initiatives.

- Deferred revenue from the current access arrangement – an adjustment to account for the amount of revenue deferred in the current access arrangement (as a result of an alternative treatment of capital contributions) which was to be recovered in subsequent access arrangement periods.

Proposed Revisions

952. Western Power has forecast adjustments to target revenue in the third access arrangement period in respect of the unforseen events adjustment, investment adjustment mechanism, service standards adjustment mechanism and a full recovery of deferred revenue from the current access arrangement period.

953. Western Power is proposing to recover $7.5 million (in real dollar terms at 30 June 2012) in 2012/13 target revenue for an unforseen event (i.e. a severe storm on 22 March 2010). Western Power has provided a description of the event, a description of its insurance cover and an estimate of the unrecovered costs.[282]

954. Under the investment adjustment mechanism, Western Power proposes to deduct $47.4 million from target revenue for the transmission network and add $2.0 million to target revenue for the distribution network (dollar values at 30 June 2012). These adjustments reflect actual spending of relevant capital expenditure being below forecast for the transmission network in the current access arrangement period and slightly above forecast for the distribution network.

955. Western Power has forecast a level of service performance for 2011/12 and determined that over the current access arrangement period it has incurred a penalty of $0.7 million for the transmission network and a reward of $3.1 million for the distribution network under the service standard adjustment mechanism. The current access arrangement requires that actual service performance for 2011/12 should be used rather than forecast, although actual performance would not be known until after 30 June 2012.

956. In the current access arrangement period, Western Power proposed an alternative treatment of capital contributions from its approach in the first access arrangement period, which had the effect of significantly increasing the revenue requirement. In its Final Decision, the Authority considered that to avoid price shocks (as required by section 6.4(c) of the Access Code) and considering that the change in treatment of capital contributions policy should have a neutral commercial effect on Western Power's business in present value terms, an amount of revenue should be deferred from the current access arrangement period to subsequent access arrangement periods. The amount of deferred revenue was $64.5 million for the transmission network and $484.2 million for the distribution network (real as at 30 June 2009).

957. Western Power has proposed to recover all of the deferred revenue in the third access arrangement period as a real annuity over the five-year period. This represents a revenue requirement of $967 million (in real 30 June 2012 dollars) during the third access arrangement period.

[282] Revised access arrangement information, Section 12.2.4, pp. 275-280.

Submissions

958. Submissions received by the Authority in relation to Western Power's proposed adjustments to target revenue are addressed below under "Considerations of the Authority".

Considerations of the Authority

959. The Authority's considerations in relation to each of the proposed adjustments to target revenue are set out below.

Correction Factor

960. The maximum reference service revenue formula included in the current access arrangement includes a correction factor which takes account of any difference between forecast maximum reference service revenue and the actual revenue earned in that year. Clauses 5.37 and 5.48 of the current access arrangement states that the correction factor will also apply in the first year of the next access arrangement period to adjust for any difference between the forecast and actual revenue in relation to the financial year commencing on 1 July 2011.

961. Western Power set the annual tariffs for 2011/12 in April 2011. As this occurred prior to the end of the 2010/11 financial year, the maximum reference service revenue was based on forecasts of revenue for both 2010/11 and 2011/12.

962. In the proposed revised access arrangement, Western Power has not indicated any adjustment to target revenue in the third access arrangement period to account for under-recovery or over-recovery of revenue under the revenue-cap in 2010/11 and 2011/12.

963. The actual revenue earned in 2010/11 is now known and should be adjusted for in the assessment of target revenue for the third access arrangement period. Although actual revenue for the 2011/12 financial year is not yet finalised, Western Power should be able to prepare a more accurate forecast of 2011/12 revenue than was possible at the time of setting tariffs for the 2011/12 year in April 2011, and include an appropriate adjustment in target revenue for the third access arrangement period.

Required Amendment 25

The proposed revised access arrangement must be amended to include an adjustment to target revenue for the third access arrangement period taking account of any under-recovery or over-recovery of revenue under the revenue cap in 2010/11 and 2011/12.

Unforseen Events Adjustment

964. The unforseen events adjustment is set out in clauses 5.4 to 5.6 of the current access arrangement as follows:

> 5.4 If a *force majeure event* occurs which results in Western Power incurring *unrecovered costs* during the *access arrangement period* then Western Power will,

as part of its proposed access arrangement for the next *access arrangement period*, provide a report to the Authority setting out:

(a) a description of the *force majeure event*;

(b) a description of the insurance cover that Western Power had in place at the time of the *force majeure event*; and

(c) a fair and reasonable estimate of the *unrecovered costs* borne by Western Power during the *access arrangement period* as a result of the occurrence of the *force majeure event*.

5.5 Pursuant to sections 6.6 to 6.8 of the Code, an amount will be added to the *target revenue* for the *covered network* for the next *access arrangement period* in respect of the *unrecovered costs* relating to a *force majeure event* which occurred in the *access arrangement period*, calculated in accordance with the methodology described in section 4 of Appendix 8 of this *Access Arrangement*.

5.6 For the avoidance of doubt, a *force majeure event* includes but is not limited to any costs arising from the introduction of an emissions trading scheme; full retail contestability; and the roll-out of Advance Interval Meters to the extent that such costs were not included in the calculation of *target revenue* for the *access arrangement period* or otherwise addressed through the Trigger Event provisions in section 8 of this *Access Arrangement*.

965. Section 4 of Appendix 8 of the current access arrangement sets out the calculation method to be used:

> This provision for revenue adjustment covers those costs (termed "unrecovered costs" in section 6.6 of the Code) which are net of any insurance payment or other cost recovery, and which were incurred prudently.
>
> It is proposed that the expenditure included in the adjustment to *target revenue* for unrecovered costs be treated as an addition to the forecast revenue entitlement submitted in the next *access arrangement period*. This amount is to be spread evenly over each year of the next *access arrangement period.*
>
> To give effect to this purpose, the adjustment to the *target revenue* for the next *access arrangement period* must leave Western Power economically neutral by taking account of:
>
> a) The effects of inflation, both in this *access arrangement period* and the next; and
>
> b) The time value of money as reflected by the real pre-tax WACC as applied in this *access arrangement period* and the next.

966. Western Power is proposing an adjustment to target revenue for the third access arrangement period of $6.9 million (in real dollar terms at 30 June 2012) to recover costs arising from a severe storm that occurred on 22 March 2010. In the proposed revised access arrangement information, Western Power notes that on 22 March 2010 a severe storm front passed over Perth bringing heavy rainfall, hail and strong winds up to 120 kilometres per hour. Western Power states that approximately 250,000 customers were affected with around 8,000 MWh of load unavailable for 31 hours and six substations affected.

967. Western Power notes that costs being claimed were recorded against specific work orders created for the March 2010 storm and include the costs of replacing uninsured assets and additional operational expenditure such as outage payments,

third party contractors engaged as a result of the event, material procured, meals and accommodation greater than usual allowances and overtime for Western Power staff or embedded contractors.

968. Western Power notes that it does not have insurance for its poles and overhead lines and provided a description of its insurance arrangements on pages 278 to 279 of the propose revised access arrangement information:

> We maintain an insurance program at a quality and coverage consistent with good electricity industry practice. At all times, our insurance has reflected the level of cover available in commercial insurance markets and is of a standard of a reasonable and prudent person.
>
> Our insurance program covers all corporate insurance exposures including property, public and products liability, motor and workers compensation, as well as other minor insurance classes. Our property insurance covers damage to physical assets including buildings, terminals and substations. Equipment other than that which is on or within 300 metres of an insured structure is not covered. The policy specifically excludes damage to transmission and distribution poles and overhead lines. All above ground transmission and distribution lines, including wire, cables, poles, pylons, towers, other supporting structures and any equipment of any type which may be attendant to such installations are not covered by an insurance policy.
>
> Prior to 2001, we had some coverage for damage to transmission and distribution poles and overhead. However, insurers have since ceased provision of this cover and as a result we are unable to obtain insurance cover for transmission and distribution poles and overhead lines.

969. Western Power included the following in relation to its claim that the amount to be claimed was in addition to insurance claims:

> At the time of the March 2010 storm, the terms of our property insurance policy required that a deductable amount of $500,000 be paid for each and every claim. The March storm caused significant damage to our uninsured poles and wires, but only minor damage to other insured assets (e.g. buildings, depots, substations).
>
> As we do not hold insurance for transmission or distribution poles or overhead wires and the total value of losses for insured assets was within our deductable amount, no claims were made against insurance policies held by the business. Therefore the unrecovered amount of $5.9 million is additional to any claims made on insurance policies.
>
> In light of the above analysis, we seek an adjustment to target revenue for AA3, in order to recover the efficient and unrecovered costs of $6.9 million in present value terms for the March 2010 storm.

970. The total amount claimed is $5.92 million (dollars June 2012). However, under the current access arrangement the adjustment to target revenue at the beginning of the third access arrangement period must leave Western Power economically neutral by taking account of inflation and the time value of money as reflected by the WACC applied in the access arrangement period. Western Power has calculated that an adjustment with a net present value at the beginning of the third access arrangement period of $6.9 million dollars (dollars June 2012) is required to be added to the target revenue in the third access arrangement period to leave Western Power economically neutral.

971. The Authority notes that the recently published report by the Standing Committee on Public Administration in relation to wood poles[283] paid particular attention to Western Power's proposed claim for the costs of the March 2010 storm, both in relation to Western Power's insurance arrangements and whether the event qualified as a force majeure event.

972. In relation to Western Power's insurance arrangements, the report noted that there was an inconsistency between statements made in Western Power's 2011 Management Representation Letter to the Auditor General and statements contained in Western Power's proposed revised access arrangement information submitted to the Authority on 30 September 2011.

973. Western Power's Management Representation Letter stated that:

> "All insurable assets and risks are to the best of our knowledge and belief fully covered by insurance."

However, as noted above, in the information submitted to the Authority, Western Power stated that its insurance policy specifically excludes damage to transmission and distribution poles and overhead lines and that all above ground transmission and distribution lines, including wire, cables, poles, pylons, towers, other supporting structures and any equipment of any type that may be attendant to such installations are not covered by an insurance policy.

974. The Committee noted in its report that it had been separately advised by one of Australia's major re-insurance companies that it is prepared to re-insure electricity network wooden power poles and that would require the assessment of risk and the setting of an appropriate re-insurance premium. The Committee also noted Western Power's responses to questions the Committee raised regarding the availability of insurance for its network wooden power poles. These are copied below[284]:

> Western Power's view is that the factors assessed by insurers, the cost of insurance and the limited scope of the cover provided has resulted in its poles not being commercially insurable. The cost of maintaining the network is not insurable.
>
> Insurance for physical damage to wooden power poles has been either unavailable or not financially feasible since 2000/01 due to reinsurance treaty restrictions.

975. The Committee took the view that there is a difference between insurance being unavailable versus not being commercially feasible. The Committee observed that generally non-disclosure of relevant information may result in an insurance policy being invalid and that if Western Power's asset records were deficient to a material extent that was not fully disclosed to an insurer and an insurance contract was entered into based on imperfect knowledge of asset condition, an insurer may have cause to avoid any subsequent claim for unassisted wooden power pole failure.

976. The Committee asked Western Power to advise whether it had adequate asset condition data for its network wooden power poles to satisfy insurance requirements and whether Western Power had made any attempts to seek insurance since 2001. The Committee's report notes that at the time the Report

---

283 Legislative Council Western Australia, Thirty-Eighth Parliament Report 14 Standing Committee on Public Administration "Unassisted Failure" January 2012, pp. 147 to 156.

284 Standing Committee Report 14, p. 148.

was adopted (January 2012), the Committee was still awaiting a satisfactory response.

977. The information provided by Western Power to the Committee was that there were strong winds up to 120 kilometres per hour. The Committee highlighted that industry standards require wooden power poles to be able to withstand winds, transverse to the relevant line, up to 140 kilometres per hour. The Committee considered that the risk of poles falling in winds up to 120 kilometres per hour, due to them having been constructed at lower standards, should have been foreseeable to Western Power.

978. The Authority acknowledges that industry standards have changed over time and that many of Western Power's wooden poles would have been installed when industry standards were lower. However, as Western Power itself acknowledged in a statement to the Committee:

> "Good industry practice is to operate the network with a good risk profile, with a good process for determining the serviceability of poles, and to replace them over time in a way that is both affordable and able to be resourced. … You can have a situation where a pole might fall at 120 kilometres per hour because it is built to an earlier standard, but it is not feasible to go out and rebuild the network every time a standard changes. "

979. The Authority agrees with the Committee's view that the risk of poles falling in winds less than 120 kilometres per hour, due to them having been constructed to an earlier standard, was foreseeable to Western Power. Western Power's pole management policy should take account of such risks when assessing the level and timescale of pole replacement and reinforcement.

980. "Force majeure" is defined in the Access Code as a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome. The Authority recognises that the March 2010 storm was a major event. However, taking account of the uncertainties raised by the Committee regarding why Western Power does not have an insurance policy covering any of its above ground transmission and distribution lines; and the fact that recorded winds during the storm were below the level that industry standards require wooden power poles to be able to withstand, the Authority does not consider that Western Power sufficiently demonstrated that it took all steps that a reasonable and prudent person would to prevent or overcome the physical and financial damage that arose from the storm.

Required Amendment 26

No adjustment to target revenue for the third access arrangement period should be made in relation to unforseen events.

Investment Adjustment Mechanism

981. The investment adjustment mechanism is set out in clauses 5.50, 5.51 and 5.53 of the current access arrangement, as follows.

> 5.50 The investment adjustment mechanism will apply to both transmission and distribution capital expenditure. The purpose of the investment adjustment

mechanism is to adjust Western Power's target revenue in the next access arrangement period in a manner that exactly corrects for the economic loss or gain to Western Power as a result of forecasting errors in relation to particular categories of capital expenditure (the investment difference) in this access arrangement period. In order to give effect to this purpose, the investment adjustment mechanism must take account of:

(a) The effects of inflation, both in this access arrangement period and the next access arrangement period;

(b) The time value of money as reflected by the real pre-tax WACC as applied in this access arrangement period and the next access arrangement period; and

(c) The cost of depreciation and the value of capital additions to the capital base at the next access arrangement period.

5.51 Given the requirements of the investment adjustment mechanism as described in section 5.50 above, Western Power's approach is to calculate the difference in present value terms between:

(a) The target revenue that would have been calculated for this access arrangement period if the investment difference had been zero (i.e. there was no forecasting error in relation to the capital expenditure categories that are subject to the investment adjustment mechanism);and

(b) The target revenue that actually applied in this access arrangement period.

The adjustment to target revenue in the next access arrangement period should be such that its present value is equal to the present value of the difference described above.

5.53 For the purposes of calculating the investment adjustment mechanism, the categories of capital expenditure that are used in calculating the investment difference are:

(a) new facilities investment arising from the connection of new generation capacity to the transmission or distribution network from 1 July 2009;

(b) new facilities investment arising from the connection of new load to the transmission system or distribution system from 1 July 2009;

(c) new facilities investment in relation to the augmentation of the capacity of the transmission system or distribution system for the provision of covered services from 1 July 2006; and

(d) new facilities investment undertaken for augmentation of the distribution system under the regional power improvement program and state underground power program.

982. Western Power has calculated amounts of adjustments under the investment adjustment mechanism as compound returns on amounts of above-forecast new facilities investment under the relevant categories at the rate of return applying under the current access arrangement (6.76 per cent pre-tax real). No allowance for depreciation has been included in the adjustments. These calculations are summarised in Table 95 and Table 96.

Table 95 Western Power's proposed adjustments to target revenue under the investment adjustment mechanism – transmission network (real $ million at 30 June 2012)

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	149.4	174.3	183.1
Customer-driven	67.2	142.9	252.5
Generation driven	28.8	147.6	97.6
Total	245.4	464.8	533.2
Actual capital expenditure (net)			
Capacity expansion	115.0	52.0	64.1
Customer-driven	23.4	24.6	33.2
Generation driven	28.6	5.0	0.0
Total	167.0	81.6	97.3
Above or (below) forecast investment			
Capacity expansion	(34.4)	(122.3)	(119.0)
Customer-driven	(43.8)	(118.3)	(219.3)
Generation driven	(0.2)	(142.6)	(97.6)
Total	(78.4)	(383.2)	(435.9)
Adjustment to target revenue Cumulative return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	0.0	(6.25)	(36.84)
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	(43.6)		

Table 96 Western Power's proposed adjustments to target revenue under the investment adjustment mechanism – distribution network (real $ million at 30 June 2012)

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	89.2	113.8	107.6
Customer-driven	106.3	106.5	106.3
State Undergrounding Power Program (SUPP)	6.0	5.8	5.7
Rural Power Improvement Program (RPIP)	8.7	0.0	0.0
Total	210.2	226.2	219.6
Actual capital expenditure (net)			
Capacity expansion	66.5	35.4	54.4
Customer-driven	140.8	156.0	128.8
State Undergrounding Power Program (SUPP)	16.4	12.0	19.6
Rural Power Improvement Program (RPIP)	8.7	-0.2	0.0
Total	232.3	203.3	202.8
Above or (below) forecast investment			
Capacity expansion	(22.7)	(78.4)	(53.2)
Customer-driven	34.5	49.5	22.5
State Undergrounding Power Program (SUPP)	10.4	6.2	13.9
Rural Power Improvement Program (RPIP)	0.0	(0.2)	0.0
Total	22.1	(22.9)	(16.8)
Adjustment to target revenue Cumulative return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	0.0	1.76	(0.07)
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	1.8		

983. In its assessment of the amounts determined by Western Power under the investment adjustment mechanism, the Authority has addressed:

- whether the amounts to be added to the target revenue for the third access arrangement period have been calculated correctly and consistently with the methods of financial modelling applied for the determination of target revenue; and
- whether the above-forecast new facilities investment is able to be added to the capital base for the network under section 6.51A of the Access Code, allowing Western Power to earn a return on the investment.

984. Consistency of the calculation of amounts to be added to target revenue with the methods of financial modelling applied for the determination of target revenue requires consistency with the implicit timing assumptions for costs and revenues and with the methods applied in calculation of the capital base. The Authority has verified the calculations of Western Power and is satisfied that the method of calculations has been undertaken appropriately. However, the Authority has not accepted the actual amounts, which are subject to the adjustment as discussed below.

985. As set out in its review of the opening capital base for the third access arrangement period the Authority has determined that not all of the capital expenditure incurred, or estimated to be incurred, during the second access arrangement period meets the requirements of section 6.51A of the Access Code and therefore has required that the amount added to the capital base be reduced from the amount proposed by Western Power. The Authority's amended capital expenditure for the second access arrangement period is set out in Table 41 above. As a consequence, the amount of adjustment under the investment adjustment mechanism also changes, as shown in Table 97 and Table 98 below.

Table 97 Authority's amended adjustments to target revenue under the investment adjustment mechanism – transmission network (real $ million at 30 June 2012)

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	149.4	174.3	183.1
Customer-driven	67.2	142.9	252.5
Generation driven	28.8	147.6	97.6
Total	245.4	464.8	533.2
Authority amended actual capital expenditure (net)			
Capacity expansion	107.9	48.6	50.1
Customer-driven	17.4	27.6	0.0
Generation driven	27.2	0.5	0.0
Total	152.6	76.7	50.1
Above or (below) forecast investment			
Capacity expansion	(41.5)	(125.6)	(133.0)
Customer-driven	(49.7)	(115.4)	(252.5)
Generation driven	(1.6)	(147.1)	(97.6)
Total	(92.8)	(388.1)	(483.1)
Adjustment to target revenue Compound return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	-	(7.4)	(38.4)
Amount added to target revenue in 2012/13 (present value at 30 June 2012)	(46.4)		

Table 98 Authority's amended adjustments to target revenue under the investment adjustment mechanism – distribution network (real $ million at 30 June 2012)

	2009/10	2010/11	2011/12 (forecast)
Forecast capital expenditure (net)			
Capacity expansion	89.2	113.8	107.6
Customer-driven	106.3	106.5	106.3
State Undergrounding Power Program (SUPP)	6.0	5.8	5.7
Rural Power Improvement Program (RPIP)	8.7	0.0	0.0
Total	210.2	226.2	219.6
Actual capital expenditure (net)			
Capacity expansion	66.6	34.9	47.5
Customer-driven	141.2	155.6	131.5
State Undergrounding Power Program (SUPP)	16.5	12.0	2.4
Rural Power Improvement Program (RPIP)	8.5	-	-
Total	232.8	202.5	181.4
Above or (below) forecast investment			
Capacity expansion	(22.6)	(78.9)	(60.0)
Customer-driven	34.9	49.1	25.2
State Undergrounding Power Program (SUPP)	10.5	6.1	(3.3)
Rural Power Improvement Program (RPIP)	(0.2)	-	-
Total	22.6	(23.7)	(38.2)
Adjustment to target revenue Compound return to 2012/13 at 7.98 per cent for 2009/10 to 2011/12	-	1.8	(0.1)
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	1.9		

Service Standards Adjustment Mechanism

986. The current access arrangement Service Standards Adjustment Mechanism (**SSAM**) provided incentives for Western Power to maintain and improve service standard performance over time. The SSAM provides financial rewards for performance improvements relative to Service Standard Benchmarks (**SSB**), and financial penalties for under-performance relative to the SSBs. The resulting net incentive reward or penalty is carried forward to contribute to the total revenue for Western Power in the first year of the third access arrangement period.

987. The provisions for the current access arrangement SSAM are set out in sections 5.15 – 5.24B of the current access arrangement. Clause 5.24A notes:[285]

> ...the reward for good performance or penalty for poor performance is remunerated by applying the applicable incentive rate to the relevant Service Standard Difference

[285] Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 15.

(**SSD**) for each year of the *access arrangement period*, which is calculated as follows:

$SSD_{2009/10} = (SSB_{2009/10} – SSA_{2009/10})$

$SSD_{2010/11} = (SSB_{2010/11} – SSA_{2010/11}) - (SSB_{2009/10} – SSA_{2009/10})$

$SSD_{2011/12} = (SSB_{2011/12} – SSA_{2011/12}) - (SSB_{2010/11} – SSA_{2010/11})$

Where:

SSD_t is the service standard difference in year t;

SSB_t is the service standard benchmark in year t; and

SSA_t is the actual service performance in year t.

988. Under clauses 5.24A(e) and 5.24B(d) of the current access arrangement, an amount must be added to or subtracted from Western Power's target revenue for the third access arrangement period which, in present value terms, is equal to the aggregate of the bonuses and penalties earned or incurred over the second access arrangement period. The intention of the present value calculation is to ensure that the amount added to or subtracted from Western Power's target revenue has the same financial effect as if the rewards or penalties applied in each year immediately following the performance year.

989. Actual service standards performance data is only available for the first two years of the current access arrangement period. Accordingly, Western Power's proposed amount includes rewards or penalties for the transmission and distribution networks that are based on forecast performance in the final year of the current access arrangement period (that is, for 2011/12). Western Power has forecast that penalties will apply for 2011/12, with a particularly large penalty for the distribution network.

990. The total adjustment proposed by Western Power relating to the performance on the transmission network during the current access arrangement is a penalty with a present value at the beginning of the third access arrangement period of -$0.7 million (real 30 June 2012 dollars).

Table 99 Transmission service standards adjustment mechanism parameters

	2009/10	2010/11	2011/12 (forecast)
Service standard benchmarks			
Circuit availability (% of total time)	98.0	98.0	98.0
System minutes interrupted - meshed (minutes)	9.3	9.3	9.3
System minutes interrupted - radial (minutes)	1.4	1.4	1.4
Actual service performance			
Circuit availability (% of total time)	98.4	97.9	97.7
System minutes interrupted - meshed (minutes)	8.9	6.7	9
System minutes interrupted - radial (minutes)	0.8	4.8	1.5
SSAM adjustment ($ million real at 30 June 2012)			
Circuit availability	1.8	-2.2	-0.8
System minutes interrupted - meshed	0.3	1.9	-1.9
System minutes interrupted - radial	0.2	-1.1	0.9
Total	**2.2**	**-1.4**	**-1.8**
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	**-0.7**		

Source: Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 271.

991. The total adjustment proposed by Western Power relating to the performance on the distribution network during the current access arrangement period is a reward with a present value at the beginning of AA3 of $2.8 million (real 30 June 2012 dollars).

Table 100 Distribution service standards adjustment mechanism parameters

	2009/10	2010/11	2011/12 (forecast)
Service standard benchmarks			
SAIDI - CBD	38	38	38
SAIDI - Urban	165	162	153
SAIDI - Rural Short	259	253	244
SAIDI - Rural Long	612	588	556
SAIFI - CBD	0.24	0.24	0.24
SAIFI - Urban	1.92	1.89	1.83
SAIFI - Rural Short	3.12	3.06	2.98
SAIFI - Rural Long	5.00	4.85	4.80
Actual service performance			
SAIDI - CBD	1	30	22
SAIDI - Urban	156	120	166
SAIDI - Rural Short	212	192	263
SAIDI - Rural Long	661	529	604
SAIFI - CBD	0.02	0.23	0.18
SAIFI - Urban	1.55	1.31	1.94
SAIFI - Rural Short	2.33	2.11	3.00
SAIFI - Rural Long	4.17	3.86	4.58
SSAM adjustment ($ million real at 30 June 2012)			
SAIDI - CBD	8.9	-7.0	1.9
SAIDI - Urban	2.2	7.9	-13.2
SAIDI - Rural Short	0.4	0.1	-0.7
SAIDI - Rural Long	-0.4	1.0	-1.0
SAIFI - CBD	2.5	-2.4	0.6
SAIFI - Urban	4.2	2.4	-7.8
SAIFI - Rural Short	0.4	0.1	-0.5
SAIFI - Rural Long	0.4	0.1	-0.4
Total	**18.5**	**2.2**	**-21.1**
Amount deducted/added from/to target revenue in 2012/13 (present value at 30 June 2012)	**2.8**		

Source: Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 272 and ERA calculations.

992. The Authority considers that the calculation by Western Power of the service standards adjustment for the AA3 period for the transmission and distribution networks is largely consistent with the mechanism set out in the current access arrangement. On this basis, the Authority accepts Western Power's overall approach.

993. However, Western Power has based its calculation of the adjustment to target revenue on a proposed weighted average cost of capital of 8.82 per cent for the 2012/13 financial year. As discussed above, the Authority has not approved Western Power's proposed weighted average cost of capital and has instead approved a post tax weighted average cost of capital of 3.87 per cent. Taking account of the revised weighted average cost of capital the Authority has recalculated a reward for the service standard adjustment in relation to the distribution service. The penalty relating to the transmission service is unchanged as the impact of correcting the weighted average cost of capital is negligible.

Required Amendment 27

The reward in relation to the service standard adjustment mechanism for the distribution service must be amended to use the Authority's approved post tax WACC of 3.87 per cent).

994. However, as outlined above, Western Power has used a forecast 2011/12 transmission and distribution networks performance to calculate the service standard adjustment. Western Power's proposed revised access arrangement includes transitional targets and incentive rates for the 2011/12 year in clause 7.5.13 which it proposes to use at the fourth access arrangement review to make any adjustment for differences between the actual performance for 2011/12 and the forecast performance. Whilst the incentive rates are consistent with those set for the second access arrangement period (indexed to June 2012 prices), the proposed transitional service standard benchmarks are not consistent with the benchmarks set for the second access arrangement. The Authority considers that the adjustment made at the beginning of the fourth access arrangement period to take account of any difference between the actual network performance in 2011/12 and the forecast performance should be based on the incentive rates and benchmarks set out in the second access arrangement.

Required Amendment 28

Section 7.5 of the proposed access arrangement must be amended to include an adjustment resulting from any differences between forecast and actual network performance in 2011/12, based on the service standard benchmarks set for the second access arrangement period – to be made to target revenue at the beginning of AA4.

Deferred Revenue

995. In the current access arrangement, Western Power proposed an alternative treatment of capital contributions from its approach in the first access arrangement

period, which had the effect of significantly increasing the revenue requirement. To avoid price shocks (as required by section 6.4(c) of the Access Code) and considering that the change in treatment of capital contributions policy should have a neutral commercial effect on Western Power's business in present value terms, an amount of revenue was deferred from the current access arrangement period to subsequent access arrangement periods.

996. Western Power has proposed to recover all of the deferred revenue in AA3 as a real annuity over the five-year period. This amounts to a revenue requirement of $967 million (in real 30 June 2012 dollars) for AA3. Western Power does not consider that recovering the deferred revenue over this period will result in a price shock. Western Power also considers it improves inter-generational equity as future users are not paying for assets used by current users and it avoids equity raising costs.

997. Until 30 September 2011, the Access Code did not include any provisions in relation to deferring revenue. An amendment to the Access Code was gazetted on 30 September 2011 to insert a new clause as set out below:

Recovery of deferred revenue

6.5A In this Chapter, **"deferred revenue"** means the amounts referred to in paragraphs 5.37A and 5.48A of the Amended Proposed Revisions dated 24 December 2009 to the *Western Power Network access arrangement*, as approved by the *Authority's further final decision* dated 19 January 2010, expressed in present value terms as at 30 June 2009 and in real dollar values as at 30 June 2009, being respectively:

(a) $64.5 million; and

(b) $484.2 million.

6.5B An amount in respect of *deferred revenue* must be added to the *target revenue* for the *Western Power Network* for one or more *access arrangement periods* until the aggregate amount referred to in section 6.5E has been added.

6.5C An amount added to the *target revenue* under section 6.5B must include an adjustment so that the deferral of the *deferred revenue* is financially neutral for the Electricity Networks Corporation, taking into account:

(a) the time value of money; and

(b) inflation.

6.5D The *Authority* must determine the amount to be added under section 6.5B in a given *access arrangement period*.

6.5E The total of all amounts added under section 6.5B (aggregated over all *access arrangement periods* for which such amounts are added) must equal:

(a) the total amount of the *deferred revenue*;

plus:

(b) the sum of all adjustments under section 6.5C.

998. The Access Code amendment does not impact on the Authority's considerations as it merely codifies what was already included in the Access Arrangement approved by the Authority for the current access arrangement period and does not prescribe over what period the revenue should be recovered with the Authority being required to determine the amount to be added to target revenue for each access arrangement period.

999. A number of submissions supported the recovery of the deferred revenue over the life of the assets.[286] Alinta and Verve Energy both rejected recovery of the deferred revenue over AA3 and suggested that it be recovered over a number of periods. Verve Energy suggested that using asset lives may be too slow a recovery process and suggests the Authority find a "middle-ground" solution, e.g. 10 years.

1000. WALGA considers that the concern about price shocks identified by the Authority during the development of the current access arrangement remain at least as relevant today as then, despite significant increases in the prices faced by electricity consumers in the intervening period. For this reason WALGA supports the proposal that deferred revenue from the current access arrangement period be recovered over the life of the assets as a more rapid recovery will result in significantly higher annual price increases.

1001. In relation to inter-generational equity, Verve Energy notes that it could also be argued that future users will accrue the benefit of current expenditure to upgrade network reliability.

1002. The Office of Energy raises concerns with the Authority's view that recovery of the deferred revenue should occur over a period equal to the average life of the network assets (some 40 to 50 years). It notes in its response:

> Though neutral in present value terms, the decision is not commercially neutral for Western Power because it fails to recognise the current funding constraints experienced by Western Power and the negative cash flow implications that would result. If funding is not available this would mean that Western Power would have to reduce its expenditure elsewhere or other Government priorities (such as health and education) may have to be reduced.
>
> The Office notes that the amount of deferred revenue to be returned is expected to grow with CPI and the time value of money. This compounding growth means that by the end of the AA3 period (30 June 2017), the original amount of $528.7 million in June 2009 dollars will have grown to over twice this amount or $1,109.4 million in nominal terms (at a notional average CPI of 2.5% and real WACC of 7%) if none was returned over the AA3 period. Western Power's debt levels would also have to increase by similar amounts, potentially impacting its ability to fund expenditure.
>
> From a consumer perspective in nominal terms deferring revenue lowers target revenue and prices in the short term, but quickly leads to higher target revenue and prices in the long term. Thus sending inappropriate signals and encouraging higher inefficient demand and increasing the requirement for network investment.

[286] Griffin Power, Landfill Gas and Power, ERM Power, WALGA.

> The Office supports Western Power's concerns that recovery over much longer periods of time could distort intergenerational equity in that future users will be paying for services enjoyed by but not paid for by current users. This may be viewed as not being efficient.
>
> The Office notes that section 7.5 of the Access Code requires the Authority, in reconciling any conflicting objectives for the pricing methods, or determining which objective should prevail, should have regard to the Access Code objective and should permit the objectives of section 7.3 to prevail over the objectives of section 7.4 (including avoiding price shocks). Section 7.3(a) states an access arrangement must have the objectives that reference tariffs recover the forward-looking efficient costs in providing reference services.
>
> We believe that Western Power's measured recovery of deferred revenue is appropriate and should be approved by the Authority.

1003. In its submission to the public consultation, Western Power states that it has a right to recover revenue that was deferred for collection from the current access arrangement period and that the revenue was deferred to help reduce price impacts during that period. Western Power considers that recovering the deferred revenue over the five years of AA3 ensures future customers do not pay more because previous customers did not pay their fair share.

1004. Western Power notes that if it recovers the revenue as proposed, the total amounts to $976 million (real dollars at 30 June 2012) compared with it being recovered over the life of the assets for which the total would be $2.9 billion (real dollars at 30 June 2012). Western Power commissioned a report from NERA and states "NERA Economic Consulting has reviewed this issue and concluded that deferring the AA2 revenue further would lead to intergenerational inequity and a requirement for Western Power to recover equity raising costs".

1005. Each element of Western Power's justification for recovery of all of the deferred revenue in AA3 is addressed below.

Price Shock Considerations

1006. The Authority's final decision in the current access arrangement to include the deferred revenue mechanism in Western Power's access arrangement had particular regard to the price control objective of section 6.4(c), being the avoidance of price shocks where a price shock is defined as a sudden material tariff adjustment between succeeding years.

1007. Under the first Access Arrangement, the value of any new facilities investment financed by contributions was added to the capital base and the value of contributions was deducted from target revenue. This treatment left Western Power financially neutral in respect of the financing of new facilities investment by contributions as it earned future revenues from depreciation allowances and a rate of return on the value of the investment added to the capital base and incurred an equivalent cost (in net present value terms) by having the value of the contributions deducted from the value of revenue able to be recovered under the price control. For the first access arrangement the Authority accepted this treatment as consistent with the requirement of section 6.51A(b) of the Access Code for the value of investment financed by capital contributions to be added to the capital base.

1008. For the current access arrangement, Western Power proposed that any new facilities investment financed by contributions would not be added to the capital base. The proposed change in treatment was also financially neutral to Western Power as it did not meet the cost of the new facilities investment that is the subject of the contribution and nothing was included in its target revenue in relation to either the expenditure or the contribution received.

1009. However, this change in treatment resulted in higher reference tariffs for the current access arrangement period than would have been the case under the previous treatment of capital contributions. To mitigate this, Western Power proposed to defer some revenue from the current access arrangement period and adjust target revenue in future periods to add amounts in respect of part or all of the deferred revenue from the second access arrangement period. This would, in effect, spread the increase in reference tariffs over a period longer than just the second access arrangement period.

1010. As set out in its final decision for the current access arrangement, the Authority considered that the avoidance of price shocks would best occur through deferring the entire amount of the resultant increment to target revenue that would occur in the second access arrangement period and a planned recovery of deferred revenue by a pre-determined schedule over an extended period, such as by a real annuity amount over a period equal to the average life of network assets. However, based on cash-flow modelling submitted by Western Power following the draft decision, the Authority accepted that recovery of deferred revenue over a long period may have adverse effects on Western Power's business due to effects on cash flows and considered that this effect on Western Power's business should be taken into consideration in determining a time path for recovery of deferred revenue that avoids price shocks for users of reference services.

1011. The Authority also noted that, following the current access arrangement draft decision, Western Power had presented projections of increases in reference tariffs to indicate that the recovery of deferred revenue may be able to occur in the third access arrangement period without a significant price shock for users. However, these projections were based on forecasts of costs that were subject to change. Consequently, the Authority determined that it would consider alternative timing of recovery, at the time of revisions to the access arrangement and having regard to the extent of any change in reference tariffs that is caused by recovery of part or all of the deferred revenue.

1012. In line with its final decision for the current access arrangement, to determine whether Western Power's proposal to recover all of the deferred revenue during AA3 results in price shock to customers, the Authority has given consideration to both the effect on tariffs relating to the recovery of deferred revenue and the overall change in reference tariffs.

1013. In its proposed revisions for AA3, Western Power has stated that it does not consider that the 'recovery of all of the deferred revenue as a real annuity causes a price shock during AA3', as the proposed average price increase for AA3 is equal to or lower than the average price increase over the current access arrangement period. The Authority notes the size of the increases under the second access arrangement were large and does not agree that just because customers have previously been subject to large price increases, that customers should continue to expect similar increases in the future.

1014. Table 101 below sets out Western Power's proposed tariff increases for AA3 and the increases Western Power's consultants, NERA, calculated would arise if the deferred revenue was recovered over the life of the assets. In its modelling, NERA has assumed that the tariff profile for the years 2013/14 to 2016/17 proposed by Western Power is retained and prices in 2012/13 are adjusted in order to achieve the target revenue required.

Table 101 Western Power's Proposed Tariff Increases Assuming Deferred Revenue is Recovered Over the Life of the Assets

	2012/13 Tariff increase %	2013/14-2016/17 Annual tariff increase %
Western Power's proposal:		
Transmission	12.9 + CPI	4.5 + CPI
Distribution	17.6 + CPI	13.4 + CPI
NERA's estimate of tariff increases if revenue was recovered over the life of the assets:		
Transmission	10.3 + CPI	4.5 + CPI
Distribution	9.6 + CPI	13.4 + CPI

1015. The Authority notes that, even without recovering all of the deferred revenue during AA3, the tariff increases proposed by Western Power are in the order of 10 per cent before adding CPI. Against this background, the Authority considers Western Power's proposal to add a further 2.6 per cent to transmission tariffs and 8 per cent to distribution tariffs results in a significant sudden and material increase compared with the tariffs in place in 2011/12.

1016. The Authority notes that the submission from the Office of Energy supports Western Power's proposal to recover all of the deferred revenue in the third access arrangement period. However, the Authority's view is that Western Power's proposal as set out in the table above would result in a price shock to customers.

Impact on Cashflows

1017. As noted above, in the Final Decision for the current access arrangement the Authority accepted that recovery of deferred revenue over a long period may have adverse effects on Western Power's business due to effects on cash flows, and considered that this should be taken into account in determining a time path for recovery of deferred revenue which avoids price shocks for customers.

1018. The Authority considers that the price control provides adequate revenue to meet the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved. As noted above, Western Power has not provided any evidence to the Authority to contradict this view.

Considerations relating to inter-generational equity

1019. The value of deferred revenue is adjusted to ensure that, regardless of the period over which it is recovered, the effect on Western Power's target revenue is neutral in NPV terms. As a result, the longer the period over which the revenue is deferred, the greater the total value of the revenue recovered in nominal terms.

1020. Western Power and the Office of Energy argue this leads to inter-generational inequity as, from a consumer perspective in nominal terms, deferring revenue results in lower prices in the short term, but leads to higher prices in the long term.

1021. In the access arrangement information Western Power submits that:

> "Recovering all deferred revenue during the AA3 period meets the Access Code objective by ... improving inter-generational equity as future users are not paying for assets used by current users."

1022. This submission by Western Power appears to be derived from a statement in the NERA report that any deferral of revenue as a response to the change in treatment of capital contributions will cause benefits of the change in treatment to be lost, including improved inter-generational equity as future users are not paying for assets used by current users.[287]

1023. It has not been established by Western Power that inter-generational equity (or more precisely equity between users paying for network services in different regulatory periods) is a relevant consideration in considering the timing of recovery of deferred revenue. Neither the Access Code objective nor the price control objectives include objectives relating to "equity".

1024. As a related matter, NERA claims that the deferral of revenue results in outcomes that are economically inefficient, in particular less "allocatively" efficient.[288] This claim derives from considerations that the deferral of revenue may result in current customers facing network tariffs less than the true cost of supply and less than the marginal cost of supply leading to "overconsumption" of network services.

1025. In the Authority's view, NERA has not established any efficiency implications of deferring revenue. Deferral of revenue and a decision whether to recover deferred revenue in AA3 or over a longer time frame does cause a shift in cost recovery and a difference in network tariffs between current and future network users. However, whether this causes inefficiency in use of network services depends upon whether and to what extent there is any resultant change in network use in response to different network tariffs. This has not been established.

1026. The reasons presented by Western Power relating to inter-temporal shifts in cost recovery and inter-generational equity therefore do not, in the Authority's view, support the case for recovering all of the deferred revenue in AA3. While it is possible that the determination of whether to recover all of the deferred revenue in AA3 or over a longer period may have efficiency implications in the use of network services, any inefficiency from recovery over a longer period has not been demonstrated.

[287] NERA, 1 September 2009, pp. 11, 12.

[288] NERA, 1 September 2009, pp. 11,12.

1027. The Authority is therefore unable to give any weight to Western Power's claim of inefficiency in assessing Western Power's proposal.

Determination of Recovery Period

1028. The Authority notes Verve Energy's view that using asset lives may be too slow a recovery process and its suggestion that the Authority find a "middle-ground" solution, e.g. 10 years. A similar suggestion was made by Alinta.

1029. As noted above, in its final decision for the current access arrangement, the Authority considered that the avoidance of price shocks would best occur by deferring the entire amount of the current access arrangement increment to target revenue and instead recover this deferred revenue by a pre-determined schedule over an extended period, such as by a real annuity amount over a period equal to the average life of network assets.

1030. The Authority has given further consideration to the period over which the deferred revenue should be recovered. The impact of various options on overall tariffs is set out in Table 102 below.

Table 102 Authority's Comparison of Different Recovery Periods for Deferred Revenue

Option	Transmission Annual % change to tariffs during AA3	Distribution Annual % change to tariffs during AA3	Overall Annual % change to tariffs during AA3
Authority's preferred approach from the current access arrangement-recovered over life of assets	**CPI - 11.4%**	**CPI + 0.3%**	**CPI - 2.3%**
Alternative A – recovered over 10 years	CPI - 10.6%	CPI + 2.5%	CPI - 0.4%
Alternative B – recovered over 5 years	CPI - 9.6%	CPI + 5.2%	CPI + 2.1%

1031. The Authority notes that reducing the recovery period from the average life of the assets to 10 years (or two access arrangement periods) results in average tariffs reducing by around 0.4 per cent per annum in real terms whilst recovering the revenue over 5 years (Western Power's proposal) results in increases in average tariffs by 2.1 per cent per annum in real terms.

1032. The Authority notes that, assuming these tariffs are passed through to retail customers, the overall increase customers would observe would be considerably less than the above figures as network charges comprise only about 40 per cent of retail tariffs.

1033. Based on the forecast price increases resulting from the Authority's draft determination, the Authority considers a recovery period of less than the life of the assets can be accommodated without resulting in a price shock to customers. For the purposes of the draft decision the Authority has adopted a period of ten years. However, the Authority will review this period when making its final decision taking account of the overall forecast price increases, to ensure it does not result in a price shock.

Required Amendment 29

The proposed access arrangement must be amended to recover deferred revenue over ten years and include a similar provision to the existing access arrangement regarding how this will be reviewed at AA4.

Tariff Equalisation Contributions

Access Code Requirements

1034. Section 6.37A of the Access Code provides for an amount to be added to target revenue in relation to tariff equalisation contributions that comprises an amount levied on users of the Western Power Network to finance amounts paid to Horizon Power for the provision of electricity services in areas not serviced by the Western Power Network:

6.37A If the service provider for the Western Power Network is or will be required, by a notice made under section 129D(2) of the Act, to pay a tariff equalisation contribution into the Tariff Equalisation Fund during an access arrangement period, then an amount may be added to the target revenue for the covered network for the access arrangement period, which amount—

(a) must not exceed the total of the tariff equalisation contributions which are or will be required to be paid under the notice, including any amount that was payable or paid before the commencement of the access arrangement period; and

(b) must be separately identified as being under this section 6.37A.

Proposed Revisions

1035. The State Government periodically gazettes the tariff equalisation contributions amounts but has yet to gazette any amounts for the tariff equalisation contribution beyond 2011/12. Western Power has included $906.9 million (in dollar values at 30 June 2012) in its target revenue for tariff equalisation contributions for AA3 which it states is based on forecasts provided in the State Budget indexed in line with inflation.

Table 103 **Tariff equalisation contributions (real $ million at 30 June 2012)**

	Current Access Arrangement			AA3				
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Approved tariff equalisation contributions[289]	129.7	180.1	181.2	-	-	-	-	-
Forecast tariff equalisation contributions[290]	-	-	-	181.2	180.7	180.8	181.7	182.5

Submissions

1036. Perth Energy does not consider the tariff equalisation contribution is an efficient tool to achieve social policy and that a better way of achieving the policy would be to use a Community Service Obligation.

Considerations of the Authority

1037. The Authority notes the submission from Perth Energy and agrees with its view that the tariff equalisation contribution is not an efficient tool to achieve social policy. However, under section 6.37A of the Access Code, an amount in respect of a tariff equalisation contribution may be added to target revenue if the service provider is required by a notice under section 129D(2) of the *Electricity Industry Act 2004* to pay the same amount into the tariff equalisation fund.

1038. The Authority notes that the price control includes a separate factor for tariff equalisation contributions. Consequently, the distribution revenue cap approved by the Authority excludes any amounts relating to tariff equalisation contributions. The Authority notes that for the purposes of forecasting a smooth revenue profile Western Power has included costs relating to the tariff equalisation contribution but these costs have then been excluded from its proposed distribution revenue cap. The Authority has adopted a similar approach to derive the approved revenue caps.

1039. The State Government has yet to gazette any amounts for the tariff equalisation contribution beyond 2011/12. If the amount of tariff equalisation contributions is not determined and gazetted in accordance with section 129D(2) of the *Electricity Industry Act 2004* prior to the Authority's final approval of the proposed access arrangement revisions, it will not be possible to have any amount included in the 2012/13 Price List (or subsequent Price Lists if an amount has not been gazetted by that time). In the absence of a tariff equalisation contribution, the manner in which the Western Australian State Government will finance the operations of Horizon Power is not a matter for the Authority to address in its determination on the proposed access arrangement revisions.

1040. For the purposes of this draft decision, the amounts submitted by Western Power have been included in forecast tariffs for illustrative purposes only.

289 Economic Regulation Authority, 4 December 2009, Final Decision, p. 272 (forecast values of 30 June 2009 divided by 0.91 to derive values in dollars of 30 June 2012).

290 Revised access arrangement information, Section 12.4, Table 88.

SERVICE STANDARD BENCHMARKS

1041. Western Power has proposed significant changes to the Service Standards Benchmarks (**SSBs**) for AA3. Service standard measures allow users to assess the value of reference services at the reference tariff, and also are an important point of reference for the application of the Service Standard Adjustment Mechanism (**SSAM**). The SSAM provides incentives for Western Power to improve service standard performance over time, and provides for penalties for under-performance.

Access Code Requirements

1042. A service standard is defined in section 1.3 of the Access Code as either or both of the technical standard, and reliability, of delivered electricity. SSBs are the benchmarks for service standards for a reference service in an access arrangement. A service provider is required to provide reference services at a standard at least equivalent to these benchmarks.

1043. Section 5.1(c) of the Access Code requires that an access arrangement include SSBs for each reference service.

1044. The requirements for SSBs are set out in section 5.6 of the Access Code. A service standard benchmark must be reasonable and must be sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

Current Access Arrangement

1045. The current access arrangement specifies SSBs for:

- transmission services;
- distribution services; and
- streetlighting.

1046. The method for deriving the SSBs involves taking the average performance on each measure for a sequence of historic monthly data.

Transmission network service standard benchmarks

1047. The transmission network service standard measures cover transmission circuits operating at 66 kV or above. Terminal station interconnecting transformers are included, but zone substation supply transformers that form the interface between the transmission and distribution systems are not.

1048. In respect of the reference services A11 and B2 available to users directly connected to the transmission network, the SSBs are expressed in terms of Circuit

Availability; System Minutes Interrupted; Loss of Supply Events; and Average Outage Duration – as defined below:[291]

- Circuit availability – refers to the availability of the transmission network. Essentially, the circuit availability benchmark is used to measure network availability and is measured as a percentage of total possible hours available (that is, the actual circuit hours available for transmission circuits divided by the total possible defined circuit hours available), where a higher percentage corresponds to a higher service standard.
- System Minutes Interrupted (for both meshed and radial transmission networks) – records the period of network outages measured in minutes and is recorded for transmission meshed and radial networks separately. A meshed network refers to an electricity network where there is more than one path between network nodes. Specifically, the system minutes interrupted benchmark is the summation of megawatt minutes of unserved energy at substations that are connected to the meshed/radial transmission network divided by the system peak megawatts. The indicator provides a measure of the minutes of peak demand not supplied as a consequence of faults on the transmission network. A lower value of system minutes interrupted corresponds to a higher service standard.
- Loss of Supply Events – records the frequency of events where the loss of supply exceeds two benchmarks (0.1 system minutes and 1.0 system minutes), where lower values on the two measures indicate a higher standard of service; and
- Average Outage Duration – records the sum of all minutes of unplanned outage divided by the total number of unplanned outage events, where a lower value indicates a higher standard of service.

1049. A range of excluded services are specified for the SSBs for transmission, including force majeure events and interruptions triggered by a third party. Planned outages are included for the Circuit Availability and System Minutes Interrupted measures, but not for the Loss of Supply Events or Average Outage Duration measures.

1050. As noted by GBA:[292]

> Unlike SAIDI and SAIFI, planned outages are included in the [Circuit Availability] measure, although the duration of extended planned outages is capped at 14 days for measurement purposes. Hence the measure captures not only the reliability of the transmission assets, but also how effectively Western Power manages asset maintenance.

Distribution network service standard benchmarks

1051. SSBs for the distribution system reference services A1 to A10, B1 and C1 are expressed in terms of two metrics – System Average Interruption Duration Index (**SAIDI**) and System Average Interruption Frequency Index (**SAIFI**). The

---

291 For detailed definitions, see Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 7 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

292 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 26.

SAIDI and SAIFI benchmarks are used as reliability measures, with a lower value corresponding to a higher service level:

- SAIDI is a measure of the total number of minutes interruption a customer experiences per annum on average;
- SAIFI is a measure of the total number of interruptions a customer experiences per annum on average.

1052. Exclusions to SAIDI and SAIFI comprise:

- major event days where the IEEE1366-2003 definition is exceeded;[293]
- outages shown to be caused by a fault or other event on the transmission system or a third party system (for instance, without limitation outages caused by an intertrip signal, generator unavailability or a customer installation);
- planned outages; and
- force majeure events.

Streetlighting service standard benchmarks

1053. In respect of reference service A9 (Streetlighting Exit Service), where Western Power is responsible for the repair of faulty streetlights, the SSBs relate to the repair times for reported faults.

Proposed revisions

1054. Western Power has proposed three significant changes to the SSBs for AA3, to:

- revise the level at which the SSBs are set, to quantify a *minimum level of service*, rather than the previous expected level of service;
- reduce the number of SSBs and change the definitions of the measures; and
- widen exclusions to include any that are accepted by the Authority in its service standard performance report.

1055. These changes are discussed in the following sections.

1056. Western Power provides supporting information for the proposed revisions to service standard benchmarks in the revised access arrangement information.[294]

---

293 In essence, the 2.5 Beta Method excludes days which exceed all but the most extreme of observed values, based on historic data. Specifically, a major event day under the 2.5 Beta Method is one in which the daily total system SAIDI value exceeds a threshold value, T_{MED}, where $T_{MED} = e^{(\alpha = 2.5\beta)}$. (Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, 17 December, p .109.

294 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, Appendix Y. Additional information relevant to the consideration of Western Power's proposed service standard benchmarks is contained in Western Power 2011, *Service Standard Performance Report Year Ending 30 June 2011*, www.erawa.com.au, September and Economic Regulation Authority 2011, *2009-10 Annual Performance Report: Electricity Distributors,* www.erawa.com.au, March.

Minimum levels of service

1057. Western Power has stated that due to not meeting all of the benchmarks set in the current access arrangement, it was at risk of non-compliance with its licence and was not entitled to receive rewards under the gain sharing mechanism.[295] To avoid this, it has proposed moving away from the target SSBs of the current access arrangement to 'minimum service' SSBs.[296]

1058. As a result, the proposed SSBs for the AA3 are generally lower than those for the current access arrangement. Instead, Western Power has proposed SSAM mechanism service standard targets which correspond to the expected value of performance – that is, the performance expected to be realised on average.

Transmission network service standard benchmarks

1059. The current and proposed transmission SSBs, and the SSAM targets, are set out in Table 104.

1060. Western Power is proposing in AA3 to discontinue the majority of the existing service standard measures for transmission (Table 104), apart from the Circuit Availability measure.

1061. In addition, a new service standard measure is proposed by Western Power for transmission services in AA3 – the Individual Customer Service Measure. This is defined as the percentage of users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:

- an account manager for the full 12 month period;
- an annually reviewed customer service management plan; and
- an invitation to participate in an annual satisfaction survey.

1062. The customer service measure benchmark for transmission reference services is set out in Table 105.

[295] Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 91.

[296] Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 91.

Table 104 Transmission system SSBs for reference services A11 and B2

	AA2 year ending June 2010 SSB and SSAM target	AA2 year ending June 2011 SSB and SSAM target	AA2 year ending June 2012 SSB and SSAM target	Proposed AA3 financial year 2013 – 2017 SSB (min. stand.)	Proposed AA3 financial year 2013 – 2017 SSAM target
Circuit Availability (% of total time)	98.0	98.0	98.0	97.3	97.8
System Minutes Interrupted (meshed network) (minutes)	9.3	9.3	9.3	np	np
System Minutes Interrupted (radial network) (Minutes)	1.4	1.4	1.4	np	np
Loss of Supply Event Frequency (Number of events > 0.1 System Minutes)	25	25	25	np	np
Loss of Supply Event Frequency (Number of events > 1 System Minutes)	2	2	2	np	np
Average Outage Duration (Minutes)	764	764	764	np	np

Note: np = 'not proposed' by Western Power as a measure for AA3

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, pp 13.

Table 105 Transmission system individual customer service measure SSBs

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	Proposed AA3 financial year
Individual customer service measure	-	-	-	100%

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 16.

1063. Western Power is proposing to set the transmission system individual customer service measure SSB at 100 per cent.

Distribution network service standard benchmarks

1064. Western Power proposes that the definition for the distribution network SAIDI and SAIFI measures be widened for AA3 to include distribution network average interruption duration and frequency that are related to interruptions arising in the transmission network. These are proposed to now be defined as follows (change italicised):[297]

- SAIDI is an annual measure of the sum of the duration of each sustained (greater that 1 minute customer interruption (in minutes) attributable to *either or both of the transmission system and distribution system* (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period;
- SAIFI is an annual measure of the total number of sustained (greater than 1 minute) customer interruptions (number) attributable to *either or both of the transmission system and distribution system* (after exclusions) divided by the average of the total number of connected *consumers* at the beginning and end of the period.

1065. The wording of the exclusions for both measures is proposed to be widened to exclude the events for the transmission network that also apply to the distribution network for these measures. In particular, exclusions cover:[298]

- For an interruption on either or both of the *transmission system* and *distribution system*, a day on which the major event day threshold, determined in accordance with IEEE1366-2003 definitions applying the "2.5 beta method", is exceeded.[299]
- Interruptions on either or both of the *transmission system* and *distribution system* shown to be caused by a fault or other event on a third party system (for instance, without limitation, interruptions caused by an intertrip signal, generator unavailability or a consumer installation).
- Planned interruptions on either or both of the *transmission system* and *distribution system* caused by scheduled *works.*
- *Force majeure* events affecting either or both of the *transmission system* and *distribution system*.

1066. The SSBs expressed in terms of SAIDI for the reference services A1 to A10, B1 and C1 for each year of the current Access Arrangement period are set out in Table 106.

---

297 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 10.

298 Ibid.

299 The Authority notes that IEEE 1366-2003 standard uses the '2.5 Beta Method' to identify major event days which are excluded from the reliability standards and individual feeder standards. A major event day under the Beta Method is one in which the daily total system SAIDI value exceeds a threshold value, T_{MED}, where $T_{MED} = e^{(\alpha = 2.5\beta)}$ (Institute of Electrical and Electronics Engineers, *1366-2003: IEEE Guide for Electric Power Distribution Reliability Indices*).

Table 106 Distribution system SAIDI SSBs and SSAM targets (minutes)

	SWIN total	CBD	Urban	Rural short	Rural long
Existing arrangement					
AA2 year ending June 2010 SSB and SSAM target	230	38	165	259	612
AA2 year ending June 2011 SSB and SSAM target	224	38	162	253	588
AA2 year ending June 2012 SSB and SSAM target	213	38	153	244	556
Proposed arrangement					
AA3 financial year proposed (minimum standard) SSB	-	56	200	360	720
AA3 financial year proposed SSAM service standard target	-	28	163	254	616

Note: The definitions of CBD, Urban, Rural Short and Rural Long feeder classification are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR).

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 77 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13 and p. 42.

1067. The SSBs expressed in terms of SAIFI for the reference services A1 to A10, B1 and C1 for each year of the current Access Arrangement period are set out in Table 107.

1068. The proposed SSBs expressed in terms of SAIDI and SAIFI for the next Access Arrangement period are shown in the last rows of Table 106 and Table 107. In both cases, Western Power is proposing to discontinue the 'SWIN total' metric. The remaining SSB metrics have significantly higher allowances – increasing by around a third in some cases compared to those applying in the current access arrangement. The proposed SSAM service targets for AA3 are also less onerous than the current access arrangement SSBs for all but the CBD. These changes reflect, among other things, the move to minimum standards for the SSBs and the inclusion of transmission interruptions in the measures.

1069. An additional two service standards for the distribution system are proposed for AA3 that were not included in the current Access Arrangement:

- Call Centre Performance percentage – measured as the number of fault calls responded to in 30 seconds divided by the total number of fault calls per year; and
- Circuit Availability – this is transmission Circuit Availability, but now included as a distribution performance measure as well.

1070. The proposed Call Centre Performance percentage for each year of AA3 for the reference services A1 to A10, B1 and C1 to C4 is shown in Table 108.

Table 107 Distribution system SAIFI SSBs and SSAM targets (events)

	SWIN total	CBD	Urban	Rural short	Rural long
Existing arrangement					
AA2 year ending June 2010 SSB and SSAM target	2.5	0.24	1.92	3.12	5.00
AA2 year ending June 2011 SSB and SSAM target	2.46	0.24	1.89	3.06	4.85
AA2 year ending June 2012 SSB and SSAM target	2.41	0.24	1.83	2.98	4.80
Proposed arrangement					
AA3 financial year proposed (minimum standard) SSB	-	0.40	2.30	4.20	5.70
AA3 financial year proposed SSAM service standard target	-	0.22	1.90	2.91	4.77

Note: The definitions of CBD, Urban, Rural Short and Rural Long feeder classification are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR).

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 7 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

Table 108 Distribution system call centre performance benchmark

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	Proposed AA3 financial year 2013 – 2017 SSB	Proposed AA3 financial year 2013 – 2017 SSAM target
Call centre performance (percentage of calls responded to in 30 seconds)	-	-	-	75%	88%

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

1071. The proposed Circuit Availability for distribution reference services is shown in Table 109. As noted, this is the identical measure to that proposed for transmission networks.

Table 109 Distribution system SSBs for circuit availability

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	Proposed AA3 financial year 2013 – 2017 SSB	Proposed AA3 financial year 2013 – 2017 SSAM target
Circuit Availability (% of total time)	-	-	-	97.3	97.8

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power,* www.erawa.com.au, p. 10 and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13.

Streetlighting service standard benchmarks

1072. The service standard measure in respect of reference service A9 (Streetlighting Exit Service) – where Western Power is responsible for the repair of faulty streetlights – is not expected to change. The only proposed change is that major regional towns will be included in the Metropolitan area.

1073. The relevant SSBs applied in relation to repair times for reported faults are set out in Table 110. The benchmarks proposed for the next Access Arrangement period are the same as for the current period.

Table 110 Streetlighting benchmarks

	AA2 year ending June 2010	AA2 year ending June 2011	AA2 year ending June 2012	AA3 proposed financial year
Metropolitan area	5 days	5 days	5 days	5 days
Major regional towns	5 days	5 days	5 days	5 days
Remote and rural towns	9 days	9 days	9 days	9 days

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 11.

Exclusions

1074. Western Power has proposed a new clause 4.5.2 in the proposed revisions for AA3 which relates to exclusions. This clause states that exclusions are usually first considered when the Authority publishes its service standard performance report under section 11.2 of the Code, and proposes that any 'exclusion accepted by the

Authority in such a report will be an exclusion for the purposes of this access arrangement and the Code'.[300]

Submissions

1075. In addition to Western Power, service standard benchmarks are addressed in submissions from:

- Alinta;
- ERM Power;
- WALGA; and
- Western Australian Major Energy Users.

1076. Alinta Sales submitted that:

- since network users have been paying tariffs through the current access arrangement that reflect a combination of operating expenditure/capital expenditure necessary to achieve the current access arrangement service standards, Western Power should not be allowed a significant reduction in its AA3 SSBs;
- some lower standards are acceptable in rural areas given the SWIN has many large rural feeders and tight SAIDI/SAIFI standards may consume a disproportionate level of operating expenditure; and
- the Authority should undertake an Australia-wide benchmarking exercise in its review.

1077. ERM Power submitted that:

- there is very little comparison of current or proposed service standards to similar standards in Australia or overseas and that AA3 Information would be enhanced by such data; and
- it is unacceptable to replace network performance standards (system minutes interrupted/loss of supply events/average outage duration) with a customer management plan.

1078. WALGA noted that street light repair times and customer service levels remain unchanged, although the measurement of these standards continues to be questioned by Local Governments.

1079. The WAMEU submission comments extensively on the proposed changes in the SSBs and the SSAM. WAMEU views may be broadly summarised in its statement that:

- service standards should improve over time;
- a service standards adjustment scheme may be detrimental for customers if performance targets are set too low, or where averaging allows targets to be achieved without improving services to some customers where the existing service is sub-standard;

300 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 17.

- if Western Power is permitted to have lower service standard targets, then the incentive scheme may become a method for rewarding average or sub-standard performance.

1080. A submission from the Western Australian Farmers Federation (**WAFarmers**) requests the Authority to consider including a service standard based on Western Power's Customer Charter with regard to the conduct of Western Power staff and contractors when entering and conducting work on farm land.

Considerations of the Authority

1081. The Authority has given separate consideration to the basis for setting SSBs, the particular service standards for which SSBs are established and the proposed SSBs, and to exclusions. These are considered in what follows. The targets for the SSAM are considered in a later section.

Setting benchmarks as minimum service standards

1082. Western Power argues that 'if the service standard benchmarks are not set at a minimum service level, additional expenditure would be required to improve the certainty the SSBs can be met'.[301]

1083. The minimum standards approach is proposed by Western Power to address two concerns. The first is to ensure that it does not breach section 11.1 of the Code, so as not to be in breach of its obligations under its transmission and distribution licences.[302] Second, Western Power notes that not meeting service standards targets results in any gain sharing mechanism surplus being foregone in a year when the SSBs are not reached.

1084. The second issue is the most salient. Western Power links the need for minimum standards to rewards under the gain sharing mechanism – noting that Clause 6.26 of the Access Code implies that gain sharing above-benchmark surplus can only be realised if all SSBs are met in a year. Clause 6.26 of the Code sets out:

> 6.26 An above-benchmark surplus does not exist to the extent that a service provider achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during the previous access arrangement period by failing to comply with section 11.1. {Note: Section 11.1 requires a service provider to maintain a service standard at least equivalent to the service standard benchmarks set out in the access arrangement or access contract.}

1085. Clause 5.14C in the current access arrangement, and now clause 7.4.3 in AA3, mirrors clause 6.26 of the Access Code.[303] Western Power states that as a result it

---

301 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 92.

302 Clause 11.1 of the Code states: 'A service provider must provide reference services at a service standard at least equivalent to the service provider's service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract.'

303 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, September, p. 39. Clause 7.4.3 of the AA3 states 'In any year in which an above-benchmark surplus is calculated to be a positive value the above-benchmark surplus

has foregone gain sharing in the current access arrangement period due to not achieving all its SSBs in 2009/10 and 2010/11.[304]

1086. The Authority acknowledges that Clause 6.26 and Section 11.1 of the Code may be interpreted to create a link between the SSBs and the gain sharing mechanism, to prevent gain sharing rewards from occurring at the expense of achievement of the SSBs.

1087. The Authority therefore accepts that there is a potential to create a significant additional penalty should a SSB not be achieved – that may not be proportionate to the resulting cost to consumers of the under-performance.

1088. In the case of the transmission network Circuit Availability service standard, the maximum revenue at risk under the SSAM was capped at 0.5 per cent of the average maximum transmission revenue during the current access arrangement period – with a resulting maximum penalty value around $2.05 million per annum ($ real at 30 June 2009) if performance was below the SSB.

1089. However, failure to achieve the Circuit Availability SSBs during each year of the current access arrangement also resulted in the loss of gain sharing surplus for each year – resulting in a significant additional penalty. For example, Western Power's average annual 'above benchmark surplus' in each year of the current access arrangement period was just under $45 million. These surpluses would have contributed to the gain sharing mechanism, but were foregone due to underperformance on one or more of the SSBs in each year of the current access arrangement period. The result was a large additional penalty for a small underperformance on any one of the SSBs.

1090. Given the foregoing penalty 'discontinuity', the Authority considers that there may have been unintended consequences from these provisions in the Access Code. On this basis, the Authority accepts that the proposed minimum SSB approach provides a means to remove the 'discontinuity' in the SSAM.

1091. The Authority notes that GBA has objected to configuring the SSBs as minimum standards, on the grounds that:[305]

> ...such benchmarks do not provide an indication of the average service levels that network users should expect to receive. Under clause 5.6 of the Access Code a service standard benchmark must be (a) reasonable and (b) sufficiently detailed and complete to enable a user to determine the value represented by the reference service at the reference tariff. In our view the benchmark levels set by Western Power are so low that they do not meet this intent. In particular they do not allow an accurate assessment of the value represented by a reference service at the reference tariff. We consider that the average service levels provided over time are a

---

does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during this access arrangement period by failing to provide reference services at a service standard at least equivalent to the service standard benchmarks for that year as set out in section 4 of this access arrangement'.

304 Western Power state that 17 out of 19 SSBs were achieved in 2009-10 and 2010-11, and that as a result, no gain sharing incentives were achieved in these years. The standards not achieved in 2009-10 related to SAIDI on long rural lines and Loss of Supply Event Frequency (number of events > 0.1 system minutes). The standards not achieved in 2010-11 related to Circuit Availability and System Minutes Interrupted (radial networks).

305 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 31.

more meaningful benchmark to use for assessing this value proposition. In our view using a minimum service standard, which Western Power can expect to exceed 97.5% of the time and usually by a significant margin, is not useful for this purpose.

1092. However, the Authority is satisfied that as the new ‘minimum standards’ SSBs levels correspond to the 97.5 per cent probability of exceedence (**PoE**) performance – relating to a defined statistical distribution – the SSBs are sufficiently detailed and complete to enable a user to determine the value represented by the reference service at the reference tariff. The Authority notes that additional information on the detail of the SSBs is provided by the corresponding service standards targets, which are informed by the 50 per cent PoE levels from the same defined statistical distributions.

1093. At the same time, the Authority is satisfied that the ‘minimum standard’ specification of the SSBs is reasonable as it addresses the disproportionate penalty effect, while not detracting from the information that allows the user to determine the value represented by the reference tariff, as noted above.

Transmission system service standards benchmarks

1094. This section considers both the requirement for transmission service standards, and the relevant SSB minimum standards.

Circuit Availability

1095. Western Power is proposing to retain the transmission Circuit Availability SSB for AA3. Western Power states that retention of this service standard recognises ‘the importance of security of the transmission network for customers that receive transmission and distribution reference services’.[306] The Authority agrees that this SSB should be retained.

1096. Western Power is proposing to set the transmission Circuit Availability SSB for AA3 at a lower ‘minimum standard’ (97.3 per cent) than the current access arrangement target (98 per cent) (see Table 104). Western Power states that all of the proposed minimum standard SSBs for AA3, including the proposed Circuit Availability minimum standard SSB, have been set in accordance with:[307]

- meeting a level of service that is likely 97.5 per cent of the time (that is a 97.5 per cent PoE level) based on the historical data for the past five years – this is considered appropriate as the basis for a minimum service standard;[308]

- the likelihood of achieving better service due to the forecast expenditure; and

---

306 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 90.

307 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 92.

308 Western Power further states that a ‘period of five years ensures that the effects of year-on-year volatility in performance is minimised and is consistent with the period used by the Australian Energy Regulator in determining targets for the Service Target Performance Incentive Scheme (Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 92).

- comparison with the current (access arrangement) SSBs.

1097. As noted above, the Authority accepts that SSBs need to be configured to minimum standards.

1098. That said, these should be retained at levels that are considered consistent with good industry practice and expectations for achievable performance over the course of AA3.

1099. The Authority notes that the equivalent SSBs set by the Australian Energy Regulator for its Service Target Performance Incentive Scheme are derived from the 50 per cent PoE average performance levels based on the most recent five years of data, while the lower bound 'collars' are set at 1.96 standard deviations away from the average performance (consistent with a 95 per cent confidence interval) (Table 111).[309] As a result, the 'collar' is set at the 97.5 per cent PoE level.

Table 111 Selected transmission circuit availability targets under the Australian Energy Regulator's Service Target Performance Incentive Scheme

	'Collar' %	Target %	Access arrangement period (ending June)
Electranet	99.10	99.47	2009-13
Powerlink[a]	97.81 – 98.01	98.40 – 99.07	2007-12
Transgrid	99.05	99.26	2009-14

Note: a) Non-critical (lower bound) and critical circuits (upper bound) range.

Source: www.aer.gov.au – various recent regulatory determinations

1100. Western Power's proposed standards are derived through a similar method to those utilised to derive the targets in Table 111 for the Australian Energy Regulator's Service Target Performance Incentive Scheme. The approach involved:[310]

- collection of data on the last six years of monthly historical data for each service standard (providing 60 observations of 'rolling 12 month' averages in each case);

309 A 'collar' under the Australian Energy Regulator's 'Service Target Performance Incentive Scheme' for electricity utilities represents a lower bound which puts a cap on the revenue at risk. Generally, revenue at risk is limited to 1 per cent of annual transmission revenue: 'to date the financial incentive (or penalty) has been limited to 1 per cent of each TNSPs maximum allowed revenue (MAR) for the relevant calendar year' (Australian Energy Regulator 2011, *Final decision :Electricity Transmission Service Providers Service Target Performance Incentive Scheme*, www.aer.gov.au, March, p. 8). In the case of distribution, 'the maximum revenue increment or decrement (the [distribution] revenue at risk) for the scheme components in aggregate for each regulatory year within the regulatory control period shall be 5%, that is, the sum of the s-factors associated with all parameters must lie between +5% (the upper limit) and –5% (the lower limit)' (Australian Energy Regulator 2011, *Electricity distribution network service providers: Service Target Performance Incentive Scheme*, www.aer.gov.au, November, p. 7)

310 Western Power 2011, *Response to GB8 and GB11*, embedded document at p2: *Statistical methodology used in determining service standard benchmark and financial incentive SSAM target levels*, www.erawa.com.au, December, p. 11.

- analysis of the data – leading to adoption of an assumption of stationarity in the data series and the application of a statistical distribution;
- determination of the statistical distribution with best fit – for example a 'Weibull' distribution was applied to the historic Circuit Availabiity data to determine the sample parameters;[311]
- application of Monte Carlo analysis involving 50,000 runs with the sample parameters, to smooth the resulting sample distribution and allow more precise estimates of the relevant probabilities of exceedence used to derive the SSBs and SSAM targets.

1101. The Authority accepts that setting the minimum standard SSB at the 97.5 per cent PoE level is a reasonable approach to address the potential penalty discontinuity associated with Clause 6.26 of the Access Code. It is consistent with the 'collar' applied by the Australian Energy Regulator's under its 'Service Target Performance Incentive Scheme'. This applies to all the SSBs – both for transmission and distribution networks.

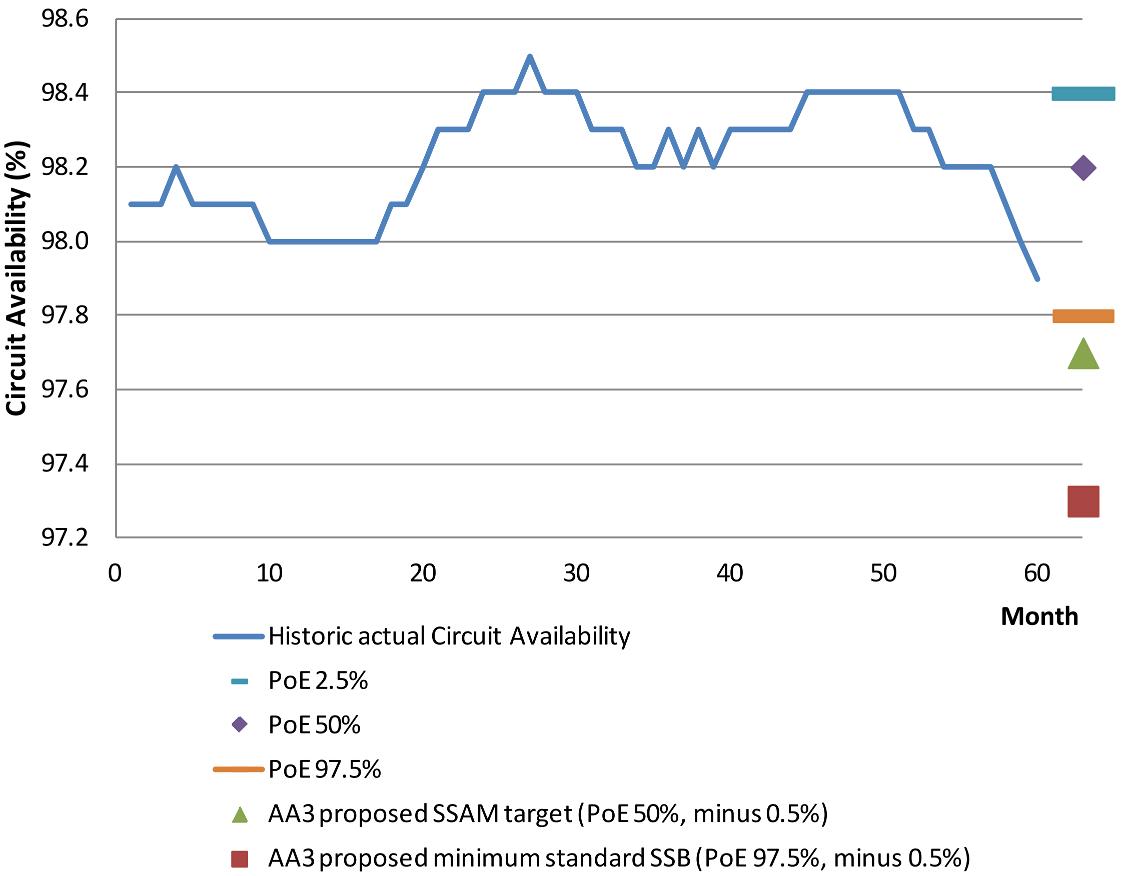
1102. In the case of the transmission Circuit Availability measure, the Authority further considers that:

- the performance over the recent 60 months of historic data does not appear to exhibit any statistically significant trend improvement in transmission circuit availability (Figure 11), hence application of a (stationary) statistical distribution of best fit to derive the initial target levels for AA3 is acceptable;[312]
- any improvement in performance in AA3, such as from the Mid West Energy Project improving Circuit Availability in the north country region, would be picked up as an improvement in the SSB level in AA4, provided that the method to derive the SSB and SSAM targets remained unchanged;
- application of Monte Carlo analysis to smooth the distribution and to derive the minimum standard SSB at the 97.5 per cent PoE level is acceptable.

[311] A Weibull distribution is a variant of an exponential distribution – its cumulative distribution function resembles a 'stretched' exponential function (see for example http://en.wikipedia.org/wiki/Weibull_distribution).

[312] A simple OLS regression has an R^2 of 0.38, when the last three observations are removed. The Authority also notes that it accepted that there would not be improvement in the transmission network performance over AA2 (see Economic Regulation Authority 2009, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, July, p. 82).

Figure 11 Circuit availability – historical performance and proposed SSB and SST



Source: Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 112; Western Power 2011, embedded spreadsheet in *Response to GB8 and GB11*, www.erawa.com.au, December, p. 3.

1103. The Authority notes that the 97.5 per cent PoE level derived from the five years of historical data used for the Circuit Availability calculation suggests a minimum standard of 97.8 per cent, given Western Power's method. However, Western Power has adjusted the level of the SSB down by 0.5 per cent – to be 97.3 per cent. Western Power states that this adjustment is to account for the proposed increased level of capital works during the AA3 period.

1104. The Authority notes that the Australian Energy Regulator's Service Target Performance Incentive Scheme has a provision to make 'reasonable adjustment' for increased levels of capital works (Clause 3.3 (k) (2) refers).[313]

1105. The Authority notes that average annual capital expenditure is set to increase in AA3 – by as much as 50 per cent or more compared to that forecast for the current access arrangement period. One driver for increased transmission investment during AA3 will be the increase in expenditure associated with the Mid West Energy Project (Southern Section).

313 Australian Energy Regulator 2011, *Electricity Transmission Service Providers Service Target Performance Incentive Scheme*, www.aer.gov.au, March, p. 8.

1106. During the review GBA asked Western Power for further information on how it calculated this additional 0.5 per cent reduction.[314] In response it provided an analysis as to how it forecast circuit availability.[315] It is apparent from Western Power's response that the major contributor to circuit unavailability is planned outages for maintenance work, including maintenance driven capital expenditure such as pole replacements (Table 112). The impact of one-off capacity expansion projects and unplanned interruptions is much less significant. However, GBA has noted that there appear to be inconsistencies in the numbers used by Western Power and GBA was unable to reproduce Western Power's forecast availability using the input numbers provided. GBA also noted that Western Power appears to have included outages for the replacement of zone substation transformers in its analysis even though the availability of these assets is excluded from the performance measure'.[316]

Table 112 Forecast Circuit Availability

	2012-13	2012-14	2014-15	2015-16	2016-17	Average 2012-17
Available circuit days	88,094	88,277	89,924	90,656	92,303	
Outage circuit days						
Unplanned	79	79	81	82	83	
Planned - capacity expansion projects	63	49	91	63	140	
Maintenance	1,563	1,615	1,666	1,724	1,721	
Subtotal	1,705	1,743	1,838	1,869	1,944	
Less adjustments for zone substation transformer replacements	28	28	28	28	28	
Total outage circuit days	1,677	1,715	1,810	1,841	1,916	
Availability	98.10%	98.06%	97.99%	97.97%	97.92%	98.01%
Western Power forecast	97.83%	97.79%	97.72%	97.70%	97.65%	97.74%

Source: Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 37.

314 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 36.

315 Western Power 2011, *Response to question GB13*, incorporating embedded document *AA3 Circuit Availability Forecast*.

316 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 37.

1107. GBA undertook its own analysis of AA3 forecast Circuit Availability and compared this with the Western Power forecast. On this basis, GBA considered that there was no apparent justification for the 0.5 per cent reduction claimed by Western Power on the basis of increased capacity expansion expenditures and associated projects. GBA's reasoning was based on a consideration of whether a change in the rate of implementation of these projects would have an impact on availability. Based on the data presented in Table 112, the overall impact of capacity expansion outages on the measure is relatively minor. Furthermore, GBA noted that the capacity expansion will also impact the normalising factor of available circuit-days. Hence, GBA concluded that an average 50 per cent PoE forecast Circuit Availability should be 98.0 per cent.[317] This compares to the 50 per cent PoE value derived from five years of historic data (with three outlier data observations removed) of 98.2 per cent. The difference is 0.2 per cent.

1108. In light of GBA's analysis, the Authority considers that a 0.2 per cent reduction in the minimum standard is justified.

Required Amendment 30

The 'minimum standard' Circuit Availability service standard benchmark must be set at 97.6 per cent. This is the estimated 2.5 per cent PoE level derived from the application of a Weibull distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during AA3.

Transmission individual customer service measure

1109. A new service standard measure is proposed by Western Power for transmission services in AA3 – the Individual Customer Service Measure. This is defined as the percentage of users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:

- an account manager for the full 12 month period;
- an annually reviewed customer service management plan; and
- an invitation to participate in an annual satisfaction survey.

1110. The Authority does not consider that this measure provides incentive for Western Power to improve its transmission networks service performance. It is a process measure which will not be related in any way to the outcomes on the transmission network.

[317] Ibid.

Required Amendment 31

To warrant the resources involved, and to relate the measure to actual performance, Western Power must include in the transmission Individual Customer Service service standard benchmark measure a reporting element relating to the outcomes of the satisfaction survey. This could be achieved by amending the definition of this measure to be:

> The percentage of users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:
>
> - an account manager for the full 12 month period;
> - an annually reviewed customer service management plan;
> - participated in an annual satisfaction survey; and
> - rated the overall performance of Western Power as satisfactory, good or excellent, but not unsatisfactory or poor.

Otherwise, this measure should not be implemented.

Other transmission service standards

1111. Western Power is proposing in AA3 to discontinue a number of the transmission service standard measures in Table 104. As noted above, these are:

- System Minutes Interrupted (for both meshed and radial transmission network) - the summation of MW minutes of unserved energy at substations which are connected to the meshed transmission network divided by the system peak MW for included services, where a lower value of system minutes interrupted indicates a higher standard of service;
- Loss of Supply Events – defined as the frequency of events where the loss of supply exceeds two benchmarks (0.1 system minutes and 1.0 system minutes), where lower values on the two measures indicate a higher standard of service; and
- Average Outage Duration – the sum of all minutes of unplanned outage divided by the total number of unplanned outage events, where a lower value indicates a higher standard of service.

1112. Western Power justifies discontinuing these measures as follows:[318]

> These are measures of the performance of the transmission network rather than the reference service received by transmission-connected customers. The definition of service standard benchmarks relating to network performance (rather than reference

---

318 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 90.

services) is not consistent with the requirement of section 5.1 of the Access Code to specify a service standard benchmark for each reference service.

1113. The Authority considers that the transmission network service is a key component for the performance of all reference services, including for reference services for large customers connected to the transmission network. To the extent that the transmission network performance is impaired, then the performance of delivery of most distribution reference services will be impaired.

1114. WAMEU stated in its submission 'the removal of these measures will provide an avenue for Western Power to avoid a clear assessment of transmission performance'.[319] ERM Power believes it is unacceptable to replace network performance standards with a customer management plan.[320]

1115. The Authority notes that these measures were introduced for the current access arrangement, given the Authority's view that transmission benchmarks 'should be consistent with those that apply to transmission businesses in the National Electricity Market'.[321]

1116. The Authority notes that the Australian Energy Regulator's transmission networks Service Target Performance Incentive Scheme includes measures relating to:[322]

- transmission circuit availability – which are subdivided into measures for critical and non-critical elements;
- loss of supply event frequency – which are subdivided into events of short duration and long duration; and
- average outage duration.

1117. The Authority considers that the System Minutes Interrupted (meshed and radial networks) can provide important performance information.[323] In particular, the Authority notes that circuit availability is sub-divided into critical and non-critical elements in the Australian Energy Regulator's Service Target Performance Incentive Scheme.[324] In this context, the System Minutes Interrupted (radial networks) provides corresponding information on critical transmission networks in Western Australia. The Authority notes that Western Power underperformed by a significant margin on this measure in 2010/11 (Table 113).[325]

319 WAMEU 2011, *Submission*, www.erawa.com.au, November.

320 ERM Power 2011, *Submission*, www.erawa.com.au, November.

321 Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, p. 104.

322 Australian Energy Regulator 2011, *Electricity transmission network service providers Service target performance incentive scheme*, www.aer.gov.au, March, p. 6.

323 Circuit availability reflects the proportion of available time that the network elements are available. System minutes interrupted is a measure of the amount of time in minutes that meshed and radial circuit elements are not available.

324 Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 43.

325 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 29.

Table 113 Current Access Arrangement System Minutes Interrupted (minutes)

	Meshed networks	Radial networks
2009-10 Benchmark	9.3	1.4
2009-10 Actual	**8.9**	**0.8**
2010-11 Benchmark	9.3	1.4
2010-11 Actual	**6.7**	**4.8**
2011-12 Benchmark	9.3	1.4

Source: Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 29.

1118. The Authority therefore does not accept Western Power's arguments for discontinuing these measures.

Required Amendment 32

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed (less critical) and radial (more critical) circuits;
- Loss of Supply Event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and
- Average Outage Duration, measured in minutes.

Table 114 provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power.

Table 114 Additional transmission SSBs and SSTs for AA3

	SSB	SST	Distribution of best fit
System minutes interrupted			
Meshed (minutes)	19	9	Normal (Johnson transformation)
Radial (minutes)	5	2	Percentile estimate
Loss of supply event frequency			
0.1 to 1 minute (events)	30.0	24.7	Normal (Johnson transformation)
Greater than 1 minute (events)	4.0	2.0	Percentile estimate
Average outage duration (minutes)	904	670	Normal

Source: Authority analysis, based on data supplied by Western Power

Market congestion measure

1119. WAMEU stated that:[326]

> WAMEU considers that the Australian Energy Regulator's STPIS approach is a well proven and provides an appropriate range of measures. It also provides a good basis for assessing comparative performance with other transmission businesses. WAMEU notes that the Australian Energy Regulator STPIS incorporates a market impact measure of performance in the incentive scheme to address the outcomes of congestion. We consider that a similar measure be incorporated in to the SSAM.

1120. In relation to the additional market congestion measure, the Authority notes that such a measure warrants consideration in terms of:

- whether there is a significant issue with transmission outages in peak times, and hence the costs to users of those outages;
- the ability for Western Power to take action to prevent such outages, and at what cost; and
- the costs of establishing such a mechanism.

1121. The Authority considers that to develop such a mechanism would require the input of Western Power, the Independent Market Operator, and other stakeholders. This consideration is not possible within the timeframe required for the AA3 determination.

326 WAMEU 2011, *Submission*, www.erawa.com.au, November.

Distribution network service standard benchmarks

1122. This section considers both the requirement for distribution service standards, and the relevant SSB minimum standards.

SAIDI and SAIFI

1123. Western Power proposes to retain for AA3 most of the distribution network unplanned SAIDI and SAIFI SSBs from the current access arrangement, but with two changes:

- exclude the unplanned SAIDI and SAIFI 'SWIN total' measures; and
- amend the retained SAIDI and SAIFI measures to include transmission outages.

Discontinuing SWIN total measures for SAIDI and SAIFI

1124. Western Power states that:[327]

> The 'SWIN total' SAIDI and SAIFI measures have been removed from the AA3 suite of service standard benchmarks because these measure reliability across the whole of the network. We already have benchmarks that measure performance by feeder category (CBD, urban, rural short, rural long) so there is no need for an additional 'whole of network' measure. We also believe that performance by feeder type is valued more highly than a total measure, as it better reflects customers' service experience. However, while 'SWIN total' is not included in the service standard benchmarks, we will continue to report publicly on reliability across the whole of the network, as required by the Authority's *Electricity Compliance Reporting Manual*.

1125. The Authority accepts that the 'SWIN total' measures for both planned and unplanned distribution network SAIDI and SAIFI will continue to be reported as part of Western Power's licence compliance obligations. The Authority also agrees that the remaining SAIDI and SAIFI measures will capture performance by feeder category. The Authority notes that the 'SWIN total' measures do not contribute to the distribution network SSAM. On this basis the Authority accepts the proposal to discontinue the reporting of the SAIDI and SAIFI 'total SWIN' SSBs.

Incorporating transmission outages in the SAIDI and SAIFI measures

1126. Western Power proposes to incorporate transmission outages in the remaining SAIDI and SAIFI measures. Western Power states that this will:[328]

> ... provide a better representation of the customer's actual experience of the service we provide.

1127. Western Power is, in essence, seeking to remove the network outage duration and frequency measures from the transmission network service standards and incentives, and to incorporate these into SAIDI and SAIFI respectively. The Authority recognises that there is some merit in providing transmission outages

---

327 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 87.

328 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 88.

within the distribution network measures. However, the Authority considers that separate information for the performance of the distribution and transmission networks – as is currently the case – allows distribution network users or applicants to assess the value of a reference tariff, as these measures are independent.

1128. The Authority also has significant concerns that the effect of this change would be to dilute the attribution of overall performance to distribution and transmission networks, and as a corollary, to obscure priorities for improvement. This change also would diminish the ability of large transmission-connected users or applicants to determine the value represented by a reference service at a reference tariff, and hence would not be consistent with the requirements of section 5.6(b) of the Access Code.[329]

1129. In addition, as noted above, the Authority does not accept Western Power's argument that transmission networks performance is unrelated to the provision of reference services, whether these be for large transmission-only customers, or for distribution customers.

1130. Finally, the Authority considers that the definition of the SSAM targets for the distribution network for 2011/12 need to be maintained – as these accounted for investments in improved service standard performance that were paid for by users during the current access arrangement period. Redefining these targets is not in the interests of network users, particularly as the Authority considers that the investments made to improve these service levels during the current access arrangement period need to be accounted for (see paragraph below).

Required Amendment 33

The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

Setting SSBs for SAIDI and SAIFI

1131. As with the transmission network measures, the Authority accepts that the SSB for these distribution network service standard measures should be configured as a minimum standard SSBs based on the 97.5 per cent PoE analysis, so as to avoid a large penalty discontinuity for under-performance.

1132. However, the Authority considers that setting the minimum standard SSBs on the basis of the most recent five years of data would not take account of the investments made during the current access arrangement, paid for by customers, to improve performance on these measures.

[329] The Access Code states (p. 65):

5.6 A service standard benchmark for a reference service must be: (a) reasonable; and (b) sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

1133. GBA observed:[330]

> In basing its targets on a 5 year history Western Power is giving less weight to the recent reliability improvements that have resulted from the improvements it has implemented in more recent times... We believe that the benefits of these improvements will be sustained into AA3 and that they should be reflected in more challenging benchmarks/SSAM targets.
>
> We therefore suggest that the AA3 access arrangement benchmarks/SSAM be set on the basis of the average performance over the three year period 2008-11.

1134. The Authority agrees with GBA that setting the AA3 targets from the more recent three years data would more fairly reflect the investments that were made in the current access arrangement to improve performance on the SAIDI and SAIFI measures.

1135. Overall, the Authority considers that the statistical method proposed for setting distribution network SSBs is acceptable.

Required Amendment 34

Western Power is required to update its analysis for the SAIDI and SAIFI service standard benchmark measures to base the service standard benchmarks on the most recent three years of data (Table 115 provides the Authority's estimates).

330 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 34.

Table 115 Revised SAIDI and SAIFI SSBs and SSTs for AA3 (based on 3 years of historic data)

	SSB	SST	Distribution of best fit
SAIDI (minutes)			
CBD	53	22	Normal
Urban	184	158	Normal (Johnson transformation)
Rural short	186	222	Normal (Box cox transformation)
Rural long	692	600	Weibull (3 parameter)
SAIFI (events)			
CBD	0.27	0.14	Logistic
Urban	1.97	1.61	Logistic
Rural short	5.4	1.71	Normal (Johnson transformation)
Rural long	5.2	4.20	Weibull (3 parameter)

Source: Authority analysis, based on historic data supplied by Western Power

Call centre performance

1136. The Authority broadly accepts Western Power's proposal for the Call Centre Performance measure, including the proposed SSBs.

1137. However, the Authority does not accept that this measure may be defined as follows:[331]

> Over a 12 month period, in relation to interruptions and life threatening emergencies, percentage of calls responded to in 30 seconds or less (after exclusions), that is:
>
> $$\frac{\text{Number of fault calls responded to in 30 seconds or less}}{\text{Total number of fault calls}}$$
>
> where:
>
> - Number of fault calls responded to in 30 seconds or less is the number of fault calls where a caller receives confirmation regarding power interruptions in their area and related restoration information, through either:

[331] Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 13.

- First speaking with a person in 30 seconds or less, or
- First receiving an automated interactive message service message in 30 seconds or less.

- A fault call is a telephone call from a caller entering the fault line or life threatening emergency line.
- The fault call response time commences when the postcode is automatically determined or when a valid postcode is entered by the caller or when the call is placed in the queue to be responded to by a human operator.

1138. The wording of the definition raises the prospect that calls are left ringing, or once answered, are simply diverted to an automated message. The performance standard should instead be defined to:

- start at the point the phone starts ringing at the call centre;
- exclude the period of time related to automated messaging – as occurs with the Australian Energy Regulator's Service Target Performance Incentive Scheme; and
- limit the time of any automated messaging.

1139. These amendments then require an exclusion to account for those callers that hang up during, or shortly after, receiving an automated message.

Required Amendment 35

The Authority requires that for the Call Centre Performance service standard benchmark measure:

- The definition point 'First speaking with a person in 30 seconds or less' be amended to:
  - 'First speaking with a person in 30 seconds or less, but excluding the time that the caller is connected to an automated interactive service (to a maximum of three minutes) that provides substantive information or elicits the caller's postcode, and which informs within the first 30 seconds that the call will be responded to by a human operator within three minutes.'
- The definition point 'First receiving an automated interactive message service message in 30 seconds or less' be deleted.
- The definition point 'The fault call response time commences when the postcode is automatically determined or when a valid postcode is entered by the caller or when the call is placed in the queue to be responded to by a human operator' be amended to:
  - 'The fault call response time commences when the call first enters the call centre and starts ringing.'

The Authority requires the exclusions be defined as follows:

One or more of:

- Calls abandoned by a caller in 4 seconds or less of their postcode being automatically determined or when a valid postcode is entered by the caller.
- Calls abandoned during the first three minutes of an automated message.
- Calls abandoned by a caller in 30 seconds or less of the call being placed in the queue to be responded to by a human operator.
- All telephone calls received on a major event day which is excluded from SAIDI and SAIFI.
- A fact or circumstance beyond the control of Western Power affecting the ability to receive calls to the extent that Western Power could not contract on reasonable terms to provide for the continuity of service.

Circuit availability

1140. As noted above at paragraphs 1126 to 1130, the Authority does not accept that transmission related performance measures should be mixed with distribution network measures.

Required Amendment 36

The Authority requires that Western Power remove transmission network Circuit Availability as a distribution network service standard benchmark measure.

CAIDI

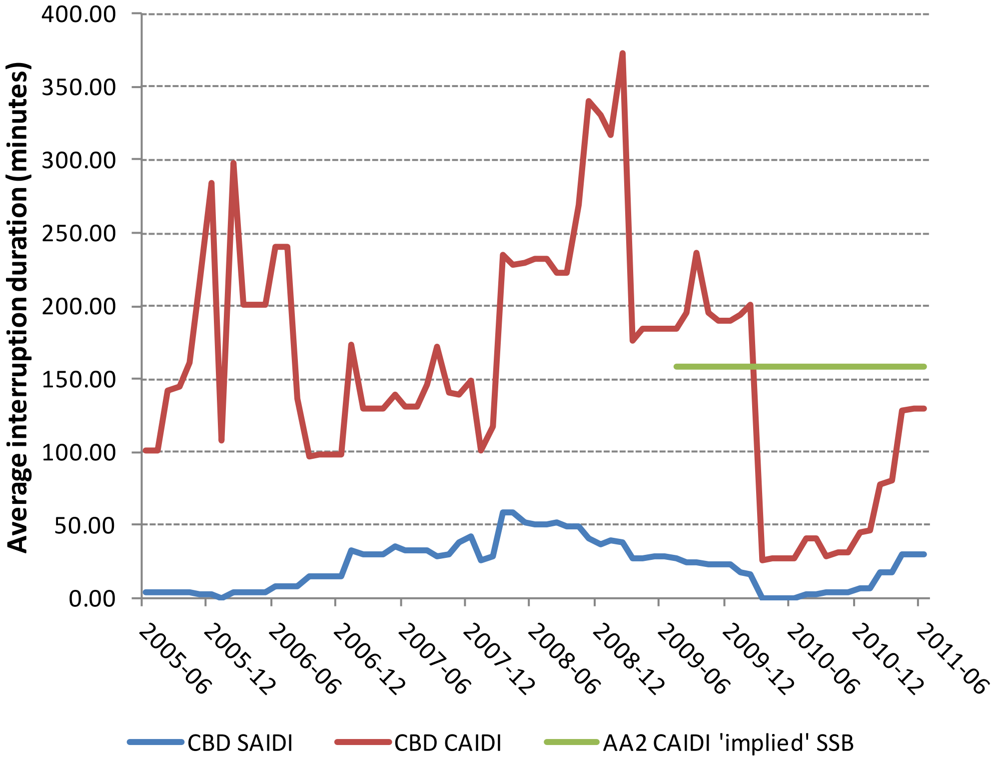
1141. The Authority notes that GBA suggests that a Customer Average Interruption Duration Interval (**CAIDI**) measure may provide more information than the existing SAIDI measure:[332]

> The customer average interruption duration (CAIDI), or average length of each interruption can be derived if SAIDI is divided by SAIFI. While this is not an AA2 benchmark indicator, it is nevertheless a useful measure of how effectively a utility responds to an interruption once it occurs. Like SAIDI and SAIFI, CAIDI is also a negative indicator.
>
> ...apart from the CBD, outage durations were generally longer than indicated by the SAIDI and SAIFI benchmarks and that, had reliability been measured in terms of SAIFI and CAIDI, Western Power's reliability performance would not have looked as good, at least superficially. This is because the improvement in SAIFI was not matched by a corresponding improvement in SAIDI.
>
> We believe that CAIDI is a useful reliability indicator since management has a high level of control over the time it takes to restore supply once an interruption has occurred. We understand the AA2 benchmarks were based on Western Power's actual performance in the years prior to the start of AA2. If this is correct, then Western Power's response to an interruption after it occurs has deteriorated over time, although we acknowledge the improvement between 2009-10 and 2010-11.

1142. It may be observed from data provided by Western Power that CAIDI on all but the CBD measure has been above an 'implied' CAIDI benchmark (Figure 12 to Figure 15).

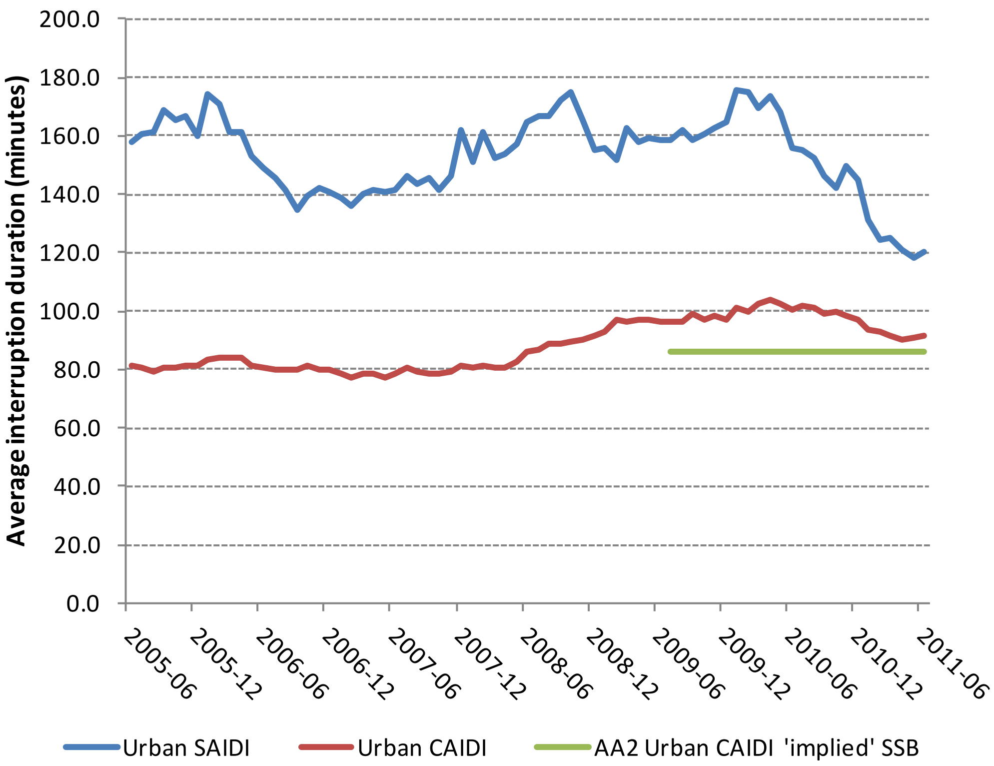
332 Geoff Brown and Associates 2012, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, www.erawa.com.au, p. 27.

Figure 12 CAIDI – CBD



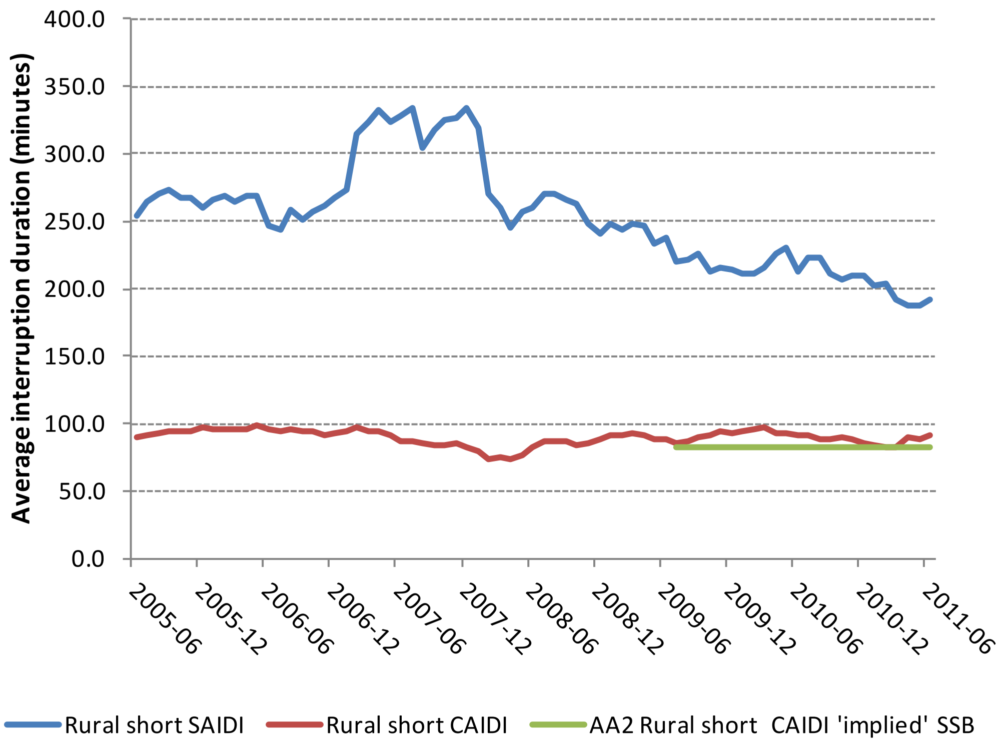
Source: Western Power 2011, embedded spreadsheet in Response to GB8 and GB11, www.erawa.com.au, December, p. 3.

Figure 13 CAIDI – Urban



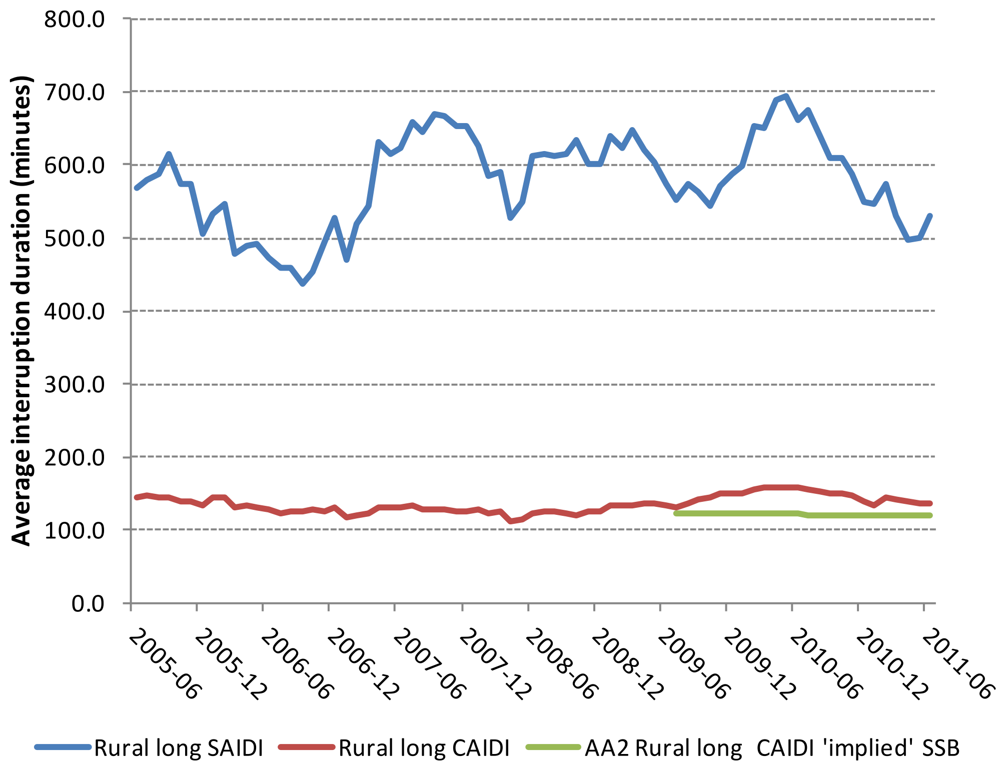
Source: Western Power 2011, embedded spreadsheet in Response to GB8 and GB11, www.erawa.com.au, December, p. 3.

Figure 14 CAIDI – Rural short



Source: Western Power 2011, embedded spreadsheet in Response to GB8 and GB11, www.erawa.com.au, December, p. 3.

Figure 15 CAIDI – Rural long



Source: Western Power 2011, embedded spreadsheet in Response to GB8 and GB11, www.erawa.com.au, December, p. 3.

1143. The Authority considers that this measure provides useful information in relation to Western Power's performance. However, the Authority notes that it may be derived from the existing performance measures, and may be volatile, depending on whether SAIDI or SAIFI is improved relatively faster over time. The Authority also notes that the Australian Energy Regulator's measures relate to SAIDI and SAIFI, not CAIDI. The Authority therefore does not require Western Power to publish this measure.

Worst performing feeders

1144. WAMEU's submission suggested that the service standards be expanded to incorporate performance on the worst performing feeders.

1145. In this context, a recent review of approaches to distribution service standards noted:[333]

> Performance targets should be set at a reasonably aggregate level, considerably less detailed than that required under the performance reporting requirements. While very detailed reporting (e.g., at the circuit level, especially for "worse performing" circuits) is valuable in a reporting context, incentive targets should not be set at this level. Nonetheless, it is important that the incentive targets distinguish between very urban, semiurban and rural regions...
>
> Reliability incentive mechanisms do not address all the issues concerning reliability since they focus on average performance. Accordingly, we recommend including supplemental measures relating to worst-served customers and preparations for extreme weather conditions. These do not necessarily have to focus on financial measures – for example, distributors could be required to publish information on the plans that they have to address these issues.

1146. The Authority notes that Western Power had a 'worst performing feeder program' but has never reported on how worst performing feeders were identified, or the performance outcomes over time.[334]

1147. The Authority notes that the Essential Services Commission of Victoria (**ESC**) evaluated approaches to reporting performance of worst performing feeders. The ESC ultimately adopted a simple, cost effective measure to identify the performance of worst performing feeders:[335]

> The distributors will... report the annual minutes off supply (SAIDI for planned and unplanned interruptions) experienced by the 15 per cent of customers... experiencing the longest time off supply in that year. Additionally, the distributors will provide a breakdown of the causes of unplanned interruptions on an annual basis into the following categories:
>
> • weather (for example, storms, rainfall, wind blown debris);
>
> • equipment failure;

333 The Brattle Group 2012, *Approaches to setting electric distribution reliability standards and outcomes*, www.aemc.gov.au, p. 14 and p. 15.

334 NAS 2005, *Service Standards for Western Power Corporation's South West Interconnected System*, www.erawa.com.au, p. 5.

335 Essential Services Commission 2006, *Electricity Distribution Price Review 2006-10: Final Decision Volume 1*, www.esc.vic.gov.au, p. 27 and p. 28.

- operational error;
- vegetation (for example, trees);
- animals (for example, possums, birds);
- third party impacts, including vehicle collisions, vandalism, dig-ins, bushfire, etc;
- transmission failure;
- load shedding;
- inter distributor connection failure; and
- other, which is to be clearly specified.

The distributors must provide an explanation for any significant, adverse year on year changes, and identify any actions to address these changes.

1148. The Authority proposed this measure in its draft decision on the current access arrangement. In a submission subsequent to the draft decision on the current access arrangement, Western Power requested that the Authority reconsider the need for a worst performing feeder measure for the reason that the SAIDI and SAIFI measures for the 15 per cent of customers served by the worst performing feeders would fulfil the same role in indications of service quality as the existing SAIDI and SAIFI measures for Rural-long feeders. Western Power indicated that the measures for the 15 per cent of customers served by the worst performing feeders would be predominantly served by rural-long feeders, and the difference in recorded SAIDI and SAIFI measures, although different, is not of sufficient magnitude to materially affect a user's assessment of the value of a reference tariff (Table 116).[336]

Table 116 Comparison of SAIDI and SAIFI for the worst 15 per cent of customers served and for rural-long feeders

	SAIDI		SAIFI	
	Worst 15% of customers served	Rural-long feeders	Worst 15% of customers served	Rural-long feeders
2005/06	631	472	5.47	3.69
2006/07	728	624	6.30	4.72
2007/08	711	611	6.03	4.99
2008/09	711	573	5.91	4.27

Source: Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, p. 112.

1149. In its final decision on the current access arrangement, the Authority accepted Western Power's contention that there would be substantial overlap between measures of SAIDI and SAIFI for the 15 per cent of customers served by the worst performing feeders and for the existing category of rural-long feeders. The

[336] Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, p. 112.

Authority also observed that there is a strong correlation between the measures for the two categories of customer groups. On this basis, the Authority considered that the service standard benchmarks for the rural-long feeders adequately capture service reliability for the worst affected customers and the Authority did not maintain the requirement for amendment of the proposed access arrangement revisions.

1150. The Authority also notes that the reliability of supply to the worst served customers may be measured by the number of customers entitled to payments for outages lasting more than 12 hours under Section 19 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*.

1151. On this basis, the Authority remains of the view that there is sufficient existing information on performance in relation to worst served customers. The Authority therefore does not require that Western Power develop such a reporting tool.

MAIFI

1152. The Authority notes that it gave attention in its final decision for the first access arrangement to a service standard that captures momentary interruptions, in particular the inclusion of a service standard benchmark for the average number of momentary interruptions of one minute or less per distribution network customer per year (as reflected by a Momentary Average Interruption Frequency Index (**MAIFI**)). The Authority did not persist in this requirement due to a submission from Western Power that it was not practically possible to accurately produce MAIFI data without a multi-million dollar investment.[337]

1153. Western Power noted as part of its AA3 submission:[338]

> During the stakeholder engagements that informed this revisions submission, customers indicated that they would value Western Power reducing the number of momentary interruptions, as even an instantaneous break in electricity supply can lead to machinery having to be reset, significantly disrupting productivity.
>
> We have listened to this feedback and are taking action to reduce the number of momentary interruptions, however, we do not currently have sufficient data to include a measure of momentary interruptions as a service standard benchmark. We will seek to improve monitoring of momentary interruptions during AA3, so that we will be in a stronger position to consider their inclusion as a service standard benchmark for AA4.

1154. The Authority notes the stakeholder feedback reported by Western Power. On this basis, the Authority considers that MAIFI is an important measure which provides information on service levels that are of value to customers.

---

337 Economic Regulation Authority 2007, *Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, www,erawa,com.au, March, paragraph 184.

338 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, September, p. 88.

Required Amendment 37

Western Power is required to collect monthly data for the average number of momentary interruptions of one minute or less per distribution network customer for each of the distribution sub-classes (CBD, Urban, Rural short and Rural long), and report these as part of its annual service standards benchmarks report to the Authority. This would provide a basis for establishing service standard benchmarks and service standard targets for the fourth access arrangement period for a Momentary Average Interruption Frequency Index measure.

Streetlighting service standards

1155. The only change proposed by Western Power for the Streetlighting service standard measure is to include major regional towns in the Metropolitan area.

1156. The benchmarks for the next Access Arrangement period are the same as for the current period.

1157. The Authority accepts this proposal.

Exclusions

1158. Western Power has included a new clause 4.5.2 in the proposed AA3 which relates to exclusions. This clause states that 'exclusions are usually first considered when the Authority publishes its service standard performance report under section 11.2 of the Code', and proposes that any 'exclusion accepted by the Authority in such a report will be an exclusion for the purposes of [the] access arrangement and the Code'.[339]

1159. The Authority notes that the annual service standard report under section 11.2 of the Code is the principal avenue for reporting on service standards performance. As part of that report, Western Power itemises exclusion events for each measure.[340]

1160. A subset of the same service standards performance data is also collected under the distribution licence reporting requirements under the *Electricity Industry Act 2004*. These data requirements are set out in the Electricity Compliance Reporting Manual.[341]

1161. The Authority does not consider that the proposed clause is acceptable as it provides incentive for Western Power to introduce exclusions without review through the annual service standard report.

---

339 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 17.

340 See for example the latest report – Western Power 2011, *Service Standard Performance Report: Year ending 30 June 2011*, www.erawa.com.au.

341 See Economic Regulation Authority 2011, *Electricity Compliance Reporting Manual*, www.erawa.com.au.

Required Amendment 38

Only those exclusions that are approved by the Authority in the access arrangement may be included for the purposes of the service standards measures. The proposed clause 4.5.2 must be removed.

WAFarmers Proposed Service Standard

1162. In its submission, WAFarmers raises concerns regarding the conduct of Western Power staff and contractors when entering and conducting work on farm land. Although Western Power's Customer Charter sets out clear guidelines for Western Power's staff and contractors, WAFarmers view is that this is often not complied with and considers that a reportable service standard measuring Western Power's performance in this area is necessary.

1163. The Authority notes that dealing effectively with issues relating to access to private property is an important component of a service provider's delivery of an efficient level of service. The Authority considers that a service standard benchmark would provide a useful measure of whether Western Power is complying with good electricity industry practice. Consequently the Authority agrees a service standard measuring compliance with Western Power's Customer Charter should be introduced. The Authority considers the benchmark should be set at 100 per cent.

Required Amendment 39

The proposed revised access arrangement should include a service standard measuring compliance with Western Power's Customer Charter. The benchmark must be set at 100 per cent.

PRICING METHODS, PRICE LIST AND PRICE LIST INFORMATION

Access Code Requirements

1165. Section 5.1(e) of the Access Code requires an access arrangement to include pricing methods in accordance with the requirements of Chapter 7 of the Access Code.

1166. Section 7.1 of the Access Code indicates that "pricing methods" means the structure of reference tariffs included in an access arrangement.

1167. Section 7.2 of the Access Code indicates that an access arrangement may contain any pricing methods; provided that the pricing methods collectively meet the objectives set out in sections 7.3 and 7.4 and otherwise comply with the requirements of Chapter 7. A note under section 7.2 also gives examples of tariffs that may result from pricing methods, indicating that tariffs or parts of tariffs may be set to take into account matters such as different classes of users, different voltage levels, different connection points, demand levels, energy quantities and times of use.

1168. Sections 7.3 and 7.4 of the Access Code set out the objectives for pricing methods, as follows:

> 7.3 Subject to sections 7.5, 7.7 and 7.12, the pricing methods in an access arrangement must have the objectives that:
>
> (a) reference tariffs recover the forward-looking efficient costs of providing reference services; and
>
> (b) the reference tariff applying to a user:
>
> (i) at the lower bound, is equal to, or exceeds, the incremental cost of service provision; and
>
> (ii) at the upper bound, is equal to, or is less than, the stand-alone cost of service provision.
>
> 7.4 Subject to sections 7.5, 7.7 and 7.12, the pricing methods in an access arrangement must have the objectives that:
>
> (a) the charges paid by different users of a reference service differ only to the extent necessary to reflect differences in the average cost of service provision to the users; and
>
> (b) the structure of reference tariffs so far as is consistent with the Code objective accommodates the reasonable requirements of users collectively; and
>
> (c) the structure of reference tariffs enables a user to predict the likely annual changes in reference tariffs during the access arrangement period; and
>
> (d) the structure of reference tariffs avoids price shocks (that is, sudden material tariff adjustments between succeeding years).

1169. Section 7.5 of the Access Code requires that the Authority, in reconciling any conflicting objectives for the pricing methods or determining which objective is to prevail, should have regard to the Code objective and where necessary must permit the objectives of section 7.3 to prevail over the objectives of section 7.4.

1170. Section 7.6 of the Access Code provides guidance for establishing components of tariffs:

> 7.6 Unless an access arrangement containing alternative pricing methods would better achieve the Code objective, for a reference service:
>
> (a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and
>
> (b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.

1171. Section 7.7 of the Access Code requires that tariffs be established as "postage stamp" tariffs in certain circumstances:

> 7.7 The tariff applying to a standard tariff user in respect of a standard tariff exit point must not differ from the tariff applying to any other standard tariff user in respect of a standard tariff exit point as a result of differences in the geographic locations of the standard tariff exit points.

1172. Section 7.9 of the Access Code provides for "prudent discounts" to be made available to some users:

> 7.9 A service provider may propose in its access arrangement to discriminate between users in its pricing of services to the extent that it is necessary to do so to aid economic efficiency, including:
>
> (a) by entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and
>
> (b) then, recovering the amount of the discount from other users of reference services through reference tariffs.

1173. Section 7.10 of the Access Code provides for discounts for users connecting distributed generation plant:

> 7.10 If a user seeks to connect distributed generating plant to a covered network, a service provider must reflect in the user's tariff, by way of a discount, a share of any reductions in either or both of the service provider's capital-related costs or non-capital costs which arise as a result of the entry point for distributed generating plant being located in a particular part of the covered network by:
>
> (a) entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and
>
> (b) then, recovering the amount of the discount from other users of reference services through reference tariffs.

1174. Section 7.11 of the Access Code requires that an access arrangement include a detailed policy setting out how discounts under sections 7.9 and 7.10 are to be applied, including a detailed mechanism for determining when a user will be entitled to receive a discount and for calculating the discount to which the user will be entitled.

1175. Section 7.12 of the Access Code requires that the value of any tariff equalisation contributions be recovered as a tariff component from users of the distribution network:

> 7.12 If an amount is added to the target revenue under section 6.37A and is intended to be recovered from users of reference services through one or more reference tariffs, then the recovery must have the objective of:
>
> (a) applying only to users of reference services provided in respect of exit points on the distribution system; and
>
> (b) being equitable in its effect as between users referred to in section 7.12(a); and
>
> (c) otherwise being consistent with the Code objective.

Price list and price list information

1176. Section 5.1(f) of the Access Code requires an access arrangement to include a price list in accordance with the requirements of Chapter 8 of the Access Code. A "price list" is defined in the Access Code as a schedule of reference tariffs.

1177. Chapter 8 of the Access Code sets out the requirements and processes for a service provider to submit price lists to the Authority for approval and for the Authority to approve or not approve a proposed price list.

1178. An access arrangement may, or may not, include a requirement on a service provider to submit price lists to the Authority for approval. A determination of whether or not price lists must be approved by the Authority occurs under section 4.36 of the Access Code.

1179. If a service provider's access arrangement requires the service provider to submit price lists to the Authority for approval, then section 8.1 of the Access Code requires that the service provider must submit a proposed price list to the Authority at least 45 business days before the start of each pricing year other than the first pricing year. A proposed price list must be accompanied by price list information. "Price list information" is defined as a document that would reasonably be required to enable the Authority, users and applicants to understand how the service provider derived the elements of the proposed price list; and to assess the compliance of the proposed price list with the access arrangement.

1180. Sections 8.2 to 8.6 of the Access Code sets out the process for the Authority to approve or not approve a proposed price list. The Authority is obliged to approve a proposed price list if it determines that the proposed price list complies with the price control and pricing methods in the service provider's access arrangement.

1181. Sections 8.7 and 8.8 of the Access Code require a service provider to submit price lists to the Authority, even if the access arrangement does not require the service provider to submit price lists to the Authority for approval. In these circumstances, the role of the Authority is to publish the submitted price list and price list information.

Current Access Arrangement

1182. "Pricing methods" are included in the current access arrangement at section 9 and indicate the allocation of costs to particular reference services and particular charges of reference tariffs.

1183. A price list (2009/10) was included in the current access arrangement at Appendix 5. Subsequent to the Authority's approval of the current access arrangement, this price list was revised to incorporate variations to reference tariff charges made in accordance with the price control for the years 2010/11 and 2011/12.

1184. The current access arrangement includes constraints on changes to reference tariffs at times of revisions of the price list. These constraints are:

- +/- (CPI + 13 percentage points) for the transmission network; and
- +/- (CPI + 18 percentage points) for the distribution network.

Proposed Revisions

1185. As noted in paragraph 166, for the purposes of calculating the maximum target revenue each year when setting annual tariffs, Western Power has proposed a number of changes:

- the published CPI data relating to the most recent December quarter compared to the December quarter in the previous year will be used rather than the March quarter which is the requirement in the existing access arrangement;
- the formula for calculating the maximum target revenue has been amended to reflect that the annual tariff-setting process for each financial year typically takes place before the end of the previous financial year so the difference in actual revenue compared to the target revenue must be estimated and then recalculated in the subsequent financial year. In the current access arrangement, this was noted in the text of the access arrangement but not explicitly included in the formula; and
- the requirements for calculating the maximum revenue cap have been changed from "will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap" to "will use its reasonable endeavours to ensure that the actual … revenue … is within a reasonable margin of [the maximum revenue cap]".

1186. As set out earlier in this draft decision in relation to Form of Price Control, Western Power is proposing to include all network access services, whether they are reference or non-reference services, within the revenue cap.

1187. As noted in paragraph 165, Western Power has proposed a new method of calculating the side-constraints for the transmission and distribution network which will vary annually based on CPI, percentage change in revenue requirements, correction factors (including an adjustment for under and over-recovery of revenue, adjustments to revenue from the current access arrangement and the TEC) and an additional 2 per cent. The formula for calculating these side constraints is contained in Western Power's proposed revised access arrangement.[342]

1188. In its proposed revised access arrangement information, Western Power notes that its pricing methods, prudent discounting policy and policy on discounts for distributed generation remain unchanged from the current access arrangement.[343]

1189. Western Power has not proposed adopting its proposed side constraint for the first year of the access arrangement but has instead proposed an amendment to the Price List Information to incorporate "tariff increase moderations."[344] This proposed amendment is outlined further in the Authority's considerations below.

1190. Four new reference tariffs have been introduced in relation to the proposed bi-directional reference services. In the proposed revised Price List Information, Western Power notes that implementation of the new tariffs will not be complete until six months after approval of the third access arrangement. Consequently, the forecast number of customers on these tariffs has been held to zero for the 2012/13 year. Western Power anticipates that in the second year of the third access arrangement customer numbers will be known and able to be forecast with some degree of accuracy so will be included in the 2013/14 estimate of revenue.[345]

1191. Western Power proposes amending the streetlight tariff to:

- update the list of streetlight asset types to include all types currently in use; and
- separate the list of streetlight asset types into "current" and "obsolete" asset types, with "current" assets being those that are still offered for installation and "obsolete" assets being those no longer offered.

Submissions

1192. The Authority received a number of submissions from interested parties in relation to Western Power's proposed pricing methods and Price List. The following matters were raised:

- concern that Western Power is proposing further large increases in prices after the substantial increases in the current access arrangement;[346]
- concern that the current practice of allocating twenty per cent of transmission use of system costs to generators is flawed and leads to inefficient outcomes;[347]
- with the increasing penetration of intermittent generation technologies, particularly domestic roof-top panels, the access arrangement needs to provide for appropriate and targeted cost recovery for the network investment necessary to accommodate the increased uptake of these services;[348]

---

342 Proposed revised access arrangement, p. 31-34.

343 Proposed revised access arrangement information, p. 308.

344 Proposed Price List Information section 8.14.

345 Proposed revised Price List, p. 7.

346 Landfill Gas and Power and Perth Energy.

347 Griffin Power and Perth Energy.

348 Perth Energy.

- the current tariff structure does not provide a strong price signal to consumers that have high demands for relatively short periods of time; and
- the existing street lighting service model results in local governments being almost powerless to influence the level of service or cost and, as street lighting is a public good the costs would be better shared between users and the public.[349]

1193. A number of submissions received by the Authority were supportive of the proposed new bi-directional tariffs.[350] Suggestions were made for further improvements such as consolidating the bi-directional tariffs with the existing exit only reference tariffs and more sophisticated time-of-use tariffs to better manage the cost of system peaks. Sustainable Energy Now suggests consideration be given to accounting for the true value of photovoltaic systems to the network and included information on price differentiation from an example based on a study by "Americans for Solar Power" from 2005 in relation to the value to grid support, avoided generation and losses, avoided distribution costs and avoided transmission costs.

1194. The Office of Energy noted in its submission that published tariffs do not exist for non-reference bi-directional services, including for plant larger than 1MVA and considers this could leave the proponents of such systems at a disadvantage in negotiating contracts with Western Power. The Office of Energy considers it would be helpful for Western Power to publish pricing guidelines for such non-reference services.

Considerations of the Authority

Target Revenue Cap

1195. As set out in this draft determination, the Authority has not approved the transmission network revenue cap and the distribution network revenue cap proposed by Western Power. Consequently, Western Power is required to amend its proposed revised Price List and Price List Information for 2011/12 to be consistent with the approved transmission network revenue cap and distribution network revenue cap target.

Required Amendment 40

The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision.

1196. The Authority acknowledges that the March CPI is not available until the end of April so cannot be incorporated in time for a Price List to be submitted to the Authority at least 45 business days before the start of pricing year. Consequently

349 WALGA.

350 Landfill Gas and Power, Sustainable Energy Now and Sustainable Energy Association of Australia.

the Authority accepts Western Power's proposed amendment to use the published CPI data relating to the most recent December quarter.

1197. The Authority notes the proposed amendment to the formula for calculating the maximum target revenue, to reflect that the annual tariff-setting process for each financial year typically takes place before the end of the previous financial year, is in line with the text of the current access arrangement and reflects how it has been done in practice. Consequently, the Authority accepts the proposed amendment so the difference in actual revenue compared to the target revenue must be estimated and then recalculated in the subsequent financial year. In the current access arrangement this was noted in the text of the access arrangement but not explicitly included in the formula.

1198. The Authority considers the requirement in the current access arrangement of "will use reasonable endeavours to ensure actual revenue does not exceed the maximum revenue cap" should not be amended to "will use its reasonable endeavours to ensure that the actual … revenue … is within a reasonable margin of [the maximum revenue cap]". Making such an amendment would be to the potential disadvantage of users as the requirement to not exceed the revenue cap is weakened. The current access arrangement would still enable the revenue target to be slightly exceeded if it was not reasonably possible to stay within the maximum revenue cap.

Required Amendment 41

Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended to be consistent with clause 5.27 and 5.38 of the current access arrangement.

1199. Under the current access arrangement only reference services are included within the revenue cap. As the Price List is required to cover only reference services, under the current access arrangement there is no need to allocate any of the revenue cap to other services.

1200. As set out earlier in this draft decision in relation to the Form of Price Control, the Authority has accepted Western Power's proposal to include all network access services, whether they are reference or non-reference services, within the revenue cap. Consequently, the target revenue will need to be allocated in some way. The Authority understands Western Power intends to achieve this by including non reference access service revenue in forecast revenue recovered when preparing the Price List Information. Western Power has advised the Authority that it has erroneously deducted standby services from its forecast transmission revenue recovered in the proposed 2012/13 Price List Information. Standby services are network access services and therefore fall within the revenue cap under Western Power's proposed revised access arrangement. The proposed Price List Information needs to be amended to correct this error.

Required Amendment 42

The proposed revised Price List for 2012/13 must be amended to include revenue from standby services in forecast transmission revenue.

1201. The Authority agrees in principle with Western Power's proposed approach of including non reference access service revenue in forecast revenue recovered when preparing the Price List Information. The proposed revised access arrangement should be amended to reflect this.

Required Amendment 43

The proposed revised access arrangement must be amended to explain how the revenue cap will be allocated between reference and non reference access services.

Side Constraints

1202. The current access arrangement includes annual side constraints of:

- +/- (CPI + 13 percentage points) for the transmission network; and
- +/- (CPI + 18 percentage points) for the distribution network.

1203. The values of these side constraints reflect the increases in target revenue for transmission and distribution in the "smoothed" tariff path for the access arrangement period and do not make provisions for rebalancing of tariffs.

1204. The side constraints Western Power has proposed for AA3 are more complex and provide for a reference tariff to be increased such that the proportional increase in nominal revenue from the reference tariff from the previous year is less than or equal to the proportional increase resulting from:

- inflation escalation;
- the year to year increase in target revenue that was determined in the financial model for the access arrangement;
- adjustments to target revenue that result from carry-over and cost pass-through mechanisms under the price control; and
- a further two per cent.

1205. This formula allows a proportional increase in revenue from the reference tariff sufficient to recover increases in costs, carryovers from the previous years and cost pass-through, plus a further two per cent. The additional two per cent allows for "rebalancing" of reference tariffs, i.e. for there to be a change in relative reference tariffs reflecting a shift in cost recovery between services.

1206. The Authority notes there is a slight difference between the specification of the formula in relation to the value of adjustments to the annual revenue cap as a proportion of the revenue cap for transmission and distribution. In practice, the difference in the specification of the adjustment parameters will probably not have a material effect on the side constraint unless there is a large departure of actual revenue from the values of target revenue that were determined in the financial model for the access arrangement. Western Power has advised that it has adopted different formulas as the likelihood of revenue variation differs for each service. However, the Authority considers it would be clearer to users if the formula for each service was consistent.

Required Amendment 44

Western Power must revise the specification of the adjustment parameters in the side constraints for transmission and distribution to make them consistent.

1207. As most of the parameter values of the side constraint (in particular the inflation, carry-over under the revenue cap and the value of the TEC) will only become known at the time of the annual revision of reference tariffs, it is not possible to predict changes in the reference tariffs ahead of these parameter values being determined.

1208. The Authority notes the concerns raised in the Verve Energy submission which queried the proposed amendments to the side constraints and considers the proposed methodology could result in uncertain and variable values and unexpected and/or unwarranted outcomes.

1209. However, the Authority notes this is the consequence of the nature of the revenue cap price control which incorporates carryovers and cost pass-throughs. That is, under the revenue cap price control Western Power is able to earn a fixed level of revenue, so any increase in customer volumes and numbers would lead to a reduction in tariffs and, conversely, a decrease in customer volumes and numbers would lead to an increase in tariffs.

1210. In its final decision in relation to the second access arrangement period, the Authority accepted that providing a regulated business with an opportunity to re-balance tariffs and tariff charges will generally provide the business with the opportunity to develop efficient tariff levels and structures. However, the revisions to reference tariffs in the second access arrangement period included a large increase in reference tariffs. The Authority considered that allowing a margin in the side constraints on tariff changes for rebalancing of tariffs would, potentially, have the effect of exacerbating price shocks for some network users. Therefore, the Authority considered that a balance between objectives of efficiency in the level and structure of reference tariffs and avoiding price shocks was best achieved by setting the side constraints on adjustments to reference tariffs at a level just sufficient to provide for recovery of target revenue and a smooth path of tariff changes over the second access arrangement period.

1211. However, as the target revenue approved by the Authority in this draft decision will lead to considerably lower tariff increases than experienced in the past, the Authority considers Western Power's proposed side constraint meets the requirement of section 7.4(d) of the Access Code to mitigate the effects of price shock on individual customers.

Pricing Methods

1212. As noted above, Western Power states in the proposed revised access arrangement information that its pricing methods are unchanged from the current access arrangement. As set out in the proposed revised Price List, Western Power determines the value of individual reference tariffs and the individual charges of the reference tariffs by applying a cost allocation model. Under this model, costs are allocated to cost pools and location zones, then to customer groups (corresponding to reference services), and then to charges that make up each reference tariff. Criteria for the allocation of costs relate generally to:

- the characteristics of a user at a connection point and measures of each user's proportional share of use of the network relative to other users; and
- the amount of costs that can be allocated to a user at a connection point such that the total charges paid by the user under a reference tariff are an amount generally between the incremental cost of service provision and the stand-alone cost of service provision.

1213. In its submission, the WAMEU notes that under a revenue cap there has been a tendency for regulators to not be involved in tariff setting as the allowed revenue is fixed and that such an approach can lead to the service provider developing tariffs which are not cost reflective. As a result the pricing signals that tariffs are intended to provide can be muted or even counterproductive.

1214. The WAMEU submission also notes that, whilst much of the capital expenditure is provided to address increases in peak demand, often the tariffs are set in terms of consumption. The submission notes it is widely recognised that the increasing penetration of air conditioning has been the major contributor to the increasing demands on networks and that, as the air conditioning load is heavily weather dependent, it has also led to a reduction in network load factors, due to the high demand occurring for relatively short periods.

1215. The WAMEU submission expresses concern that the continuing approach for tariffs to reflect consumption means that there is a trend for high load factor consumers to subsidise consumers with low load factors. Whilst this loss of cost reflectivity provides a benefit to low load factor consumers, it also avoids providing price signals to those who are causing the bulk of the need for increased peak capacity in the networks.

1216. The WAMEU submission recommends that the Authority should require Western Power to develop tariffs that:

- are cost reflective as this provides equity to all; and
- provide a strong price signal to consumers that have high demands for relatively short periods of time.

1217. The WAMEU submission contends that, unless there are tariff changes along these lines, Western Power will continue to seek the large increases in revenue to manage the increase in peak demand that could be mitigated if there was a more appropriate tariff structure.

1218. The submission from Landfill Gas and Power notes it has found the network tariffs to be reasonable since their inception but considers there is now a need for a new class of time of use tariffs in order to promote more efficient use of the network, which is especially relevant in managing the costs of system peaks. It notes the current time-of-use tariffs adhere to the traditional broadly defined "peak" and "off-peak" time periods have no regard for seasonality, public holidays or other "shoulder" features and notes that, whereas the Wholesale Electricity Market (WEM) facilitates the development of innovative time of use tariff signals, these signals are dissipated when combined with the averaging implicit in the network tariffs.

1219. Submissions from both Griffin Power and ERM Power take the view that the current practice of allocating 20 per cent of TUOS charges to generators is fundamentally flawed. ERM Power considers this leaves generators exposed to open-ended changes in network charges that are not quantifiable at the time of a power station investment decision. ERM Power provided the Authority with a paper prepared by Synergies Economic Consulting which it considers sets out the shortcomings of Western Power's current arrangements for setting transmission use of system charges and identifies an alternative pricing model.

1220. Synergies Economic Consulting argues that the TUOS charge allocation to generators is inconsistent with the Code, because:[351]

- it imposes a risk on prospective generator investors to which they are individually unable to respond once the generation investment is made, with the consequence that generation entry will be delayed or less capacity will be installed than would otherwise be the case;
- it presents weaker incentives for load to reduce peak demand and for generators to increase peak output than would otherwise be the case, thereby reducing the efficiency of investment in, operation of and use of the network;
- there are no offsetting efficiency benefits arising from the generator TUOS charges, such as improved decision making over location, lower transaction cost or guaranteed access to network services for generators, that offset these outcomes; and
- the regulation of transmission in Australia reduces the importance of TOUS as a signal of future efficient Transmission Network Service Provider (**TNSP**) investment.

1221. The Authority notes the points in the Synergies Economic Consulting paper and the proposed alternative approach. The Authority is not convinced, however, that the proposed generator Transmission Use of System (**TUOS**) charge allocation is inconsistent with the economic efficiency objectives of the Code:

- all market participants face risks relating to future network charges – if generators do not wish to bear those risks, then they should be able to manage the identified risks through contractual arrangements;
- the incentives for loads to manage their peak demands remain significant; and
- allocation of TUOS charges to generators does provide some locational signalling, as Western Power's transmission pricing model allocates transmission costs on the basis of the costs of the network assets used by a

351 Synergies Economic Consulting 2012, *Revision of the Generator Transmission Use of System Charges in Western Australia: A report for NewGen*, www.erawa.com.au, p. 40.

connection at any particular location, which vary across Western Power's network.

1222. That said, the Authority considers that this issue is complex. Consideration of the proposed alternative arrangements should be incorporated with that of other potential reforms to improve the overall market arrangements – as part of the review of the Access Code.

1223. The Authority considers some of the points raised in submissions have merit. However, in considering the pricing methods under the proposed access arrangement revisions, the Authority does not have a role in approving levels and structures of reference tariffs to the level of detail that would enable the Authority to impose particular tariff structures, such as those proposed in these submissions.

1224. The role of the Authority in assessing and approving the magnitude and structure of particular reference tariffs is limited. The Authority is only concerned with whether the proposed pricing methods will result in reference tariffs meeting the requirements of section 7.2 of the Access Code, and the objectives of sections 7.3 and 7.4 of the Access Code. The efficiency requirements of these objectives are broad, requiring only that the reference tariffs recover the forward-looking efficient costs of providing reference services and that the reference tariff applying to a user recovers an amount of revenue that is greater than the incremental cost of service provision and less than the stand-alone cost of service provision.

1225. Taking the above matters into account, the Authority is satisfied that the pricing methods applied by Western Power are consistent with the objectives of sections 7.3 and 7.4 of the Access Code.

Proposed Price List for 2012/13

1226. Western Power has not applied its proposed side constraints to the proposed price list for the 2012/13 financial year.[352] Instead it notes in the proposed Price List Information[353] that its intention at the start of the third access arrangement period is to set all prices to their cost reflective levels after many years of flat scaled increases.

1227. Western Power notes in the proposed Price List Information that:

> Unfortunately, this method results in unrealistic outcomes for some tariffs. In order for some customers not to be unduly disadvantaged in year one, some of the tariff increases and decreases have been slightly modified.
>
> Specifically, increases for RT4 and RT10 were slightly reduced to be more in line with the increases in other tariffs. As the increases for RT6-RT8 were lower than average, the decision was made to slightly increase these tariffs to enable moderation of large increases in other tariffs. This approach is similar to how the side-constraints will operate during AA3.
>
> This decision means that revenue from RT4 is not between incremental and stand-alone costs in the first year. However, RT4 revenue should move to the cost

352 Access Arrangement Information, p. 314.

353 Appendix F.2, p. 73.

reflective level over the course of the AA3 period (with inter-year movements subject to the side constraints proposed in the Access Arrangement).

1228. The Authority notes there is significant variation in Western Power's estimate of the incremental and stand-alone cost of service provision costs between the approved Price List Information for 2011/12 and the proposed Price List Information for 2012/13. The changes between the two years vary between a reduction of 0.1 per cent in the incremental cost for the RT2 reference tariff and a 56 per cent increase in the incremental cost for the RT4 reference tariff. There also appears to be little relationship between the change in incremental cost of service and the stand-alone cost of service provision for each reference tariff. For example, the incremental cost for the RT6 tariff has increased by 33 per cent compared with the previous year whereas the stand-alone cost of service provision has reduced by 1 per cent.

1229. Given that Western Power states that it has not changed its pricing methods from the current access arrangement, the significant variations appear strange. Western Power has not provided any explanation or information about why its assessment of incremental and stand-alone costs vary so significantly from the current approved price list. The Authority notes that the estimated costs will reduce as a result of the Authority not approving Western Power's proposed target revenue. The Authority requires Western Power to amend its calculations of incremental and stand-alone costs to take account of the level of target revenue approved in this draft decision by the Authority. Western Power should also include commentary in its proposed revised Price List for 2012/13 to explain any material variations in the estimate of incremental and stand-alone costs to enable customers to understand how Western Power derived the elements of the proposed price list as required under section 1.3 of the Access Code.

Required Amendment 45

The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision. Western Power should include commentary to explain any material variations in its estimate of incremental and stand-alone costs compared with the current 2011/12 Price List Information.

1230. Section 7.5 of the Access Code requires that the Authority, in reconciling any conflicting objectives for the pricing methods or determining which objective should prevail, should have regard to the Code objective and, where necessary to reconcile a conflict, should permit the objectives of section 7.3 to prevail over the objectives of section 7.4. The effect of this is that the requirement that tariffs should be set somewhere between the incremental and stand-alone cost of providing the relevant service prevails over the requirement to avoid sudden material tariff adjustments between succeeding years.

1231. Consequently, after adjusting its estimates of incremental and stand-alone costs as required above, Western Power needs to ensure all tariffs are set between incremental and stand-alone cost to comply with section 7.3 of the Access Code.

Required Amendment 46

All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.

1232. Notwithstanding the significant variations in incremental and stand alone costs compared to those estimated in the 2011/12 Price List Information and the requirement to ensure tariffs are set between incremental and stand-alone cost, the Authority notes there is a wide variation in the percentage change to specific tariffs for 2012/13 compared with 2011/12 ranging from -53 per cent to +118 per cent. Whilst the Authority recognises that, if Western Power has only been applying flat scaled increases over many years, there may be a divergence from their cost reflective levels, it considers that as far as possible whilst still complying with section 7.3 of the Access Code, any rebalancing should be phased in over a period of time so as to avoid sudden material tariff adjustments between succeeding years as required under section 7.4 (d) of the Access Code. To ensure the requirements of section 7.4(d) of the Access Code are met, the Authority requires Western Power's proposed side constraint to also apply to the first year of the third access arrangement period.

Required Amendment 47

Western Power's proposed side constraint must apply from the first year of the third access arrangement.

1233. Taking account of the matters noted above, the Authority is not satisfied that Western Power's proposed tariffs for 2012/13 are consistent with the objectives of sections 7.3 and 7.4 of the Access Code and requires the amendments outlined in paragraphs 1226 to 1232 to be made.

Bi-directional Tariffs

1234. The Authority considers the views expressed in submissions in relation to further improvements such as consolidating the bi-directional tariffs with the existing exit only reference tariffs and more sophisticated time-of-use tariffs to better manage the cost of system peaks should be given consideration by Western Power in the future. However, given the general support expressed in submissions for the proposed tariffs and the pragmatic approach Western Power has taken of basing the proposed bi-directional tariffs on the proposed exit only tariffs, the Authority considers the proposed tariffs meet the requirements of sections 7.3 and 7.4.

1235. The Authority notes the Office of Energy's view that it would be helpful for pricing guidelines to be published in relation to non-reference bi-directional services for plant larger than 1 MVA. However, there is no requirement under the Code for guidelines for non-reference services to be published.

1236. As discussed above in paragraph 130, the threshold for the proposed business bi-directional tariffs of 1 MVA is consistent with the Access Code requirement for the use of average, non-locational tariffs for all connections below 1 MVA. Western

Power has advised that the threshold of 1MVA will allow the reference service to cover the greater portion of the market for bi-directional services and that installations above 1MVA would be charged on the basis of the existing entry and exit reference services for distribution customers (A8 and B1).

Streetlight Tariffs

1237. The Authority notes the points raised by WALGA that the existing street lighting service model results in local governments being almost powerless to influence the level of service or cost and, as street lighting is a public good, the costs would be better shared between users and the public. The Authority acknowledges there are different, and potentially better, models for recovering the cost of street lighting. However, for the purposes of this review the Authority can only apply the requirements of the Access Code which provides for Western Power to recover its efficient costs through network charges and that tariffs comply with sections 7.3 and 7.4 of the Access Code.

1238. The Authority has reviewed the updated list of streetlight asset types included in the proposed revised Price List for 2012/13. The Authority notes that Western Power has added 10 new asset types to the list of streetlight assets. However, all of the new asset types have been included in Table 3 of the Price List which relates to obsolete asset types. No submissions were received in relation to the addition of new asset types. Given that the new types relate to obsolete light types, the Authority would be concerned if these proposed changes lead to increases in charges to users and requires Western Power to ensure that its proposed new asset listing does not result in assets moving to a higher charging band than is currently the case.

Required Amendment 48

Western Power's proposed additions to streetlight asset types must ensure existing assets are not charged on a higher band compared with the current access arrangement.

ADJUSTMENTS TO TARGET REVENUE IN THE NEXT ACCESS ARRANGEMENT PERIOD

Access Code Requirements

1239. Sections 6.6 to 6.32 of the Access Code provide for the target revenue for an access arrangement period to be adjusted to reflect certain events, or outcomes of the previous access arrangement period. In the circumstances of the access arrangement for the Western Power Network, these provisions of the Access Code provide (to the extent enabled by the access arrangement) for the target revenue for the fourth access arrangement period (due to commence on 1 July 2017) to be adjusted for the relevant events, or outcomes in the third access arrangement period.

1240. The events and outcomes that may give rise to adjustments to target revenue under these sections of the Access Code are:

- the service provider incurring certain costs during the AA3 as a result of unforeseen (force majeure) events (sections 6.6 to 6.8 of the Access Code);
- the service provider incurring greater or lesser non-capital costs or capital-related costs as a result of changes in the Technical Rules for the Western Power Network (sections 6.9 to 6.12 of the Access Code);
- the amount, nature and timing of new facilities investment in AA3 being different to that forecast for that period, consistent with an investment adjustment mechanism set out in the access arrangement (sections 6.13 to 6.18 of the Access Code);
- demand growth and/or efficiency gains achieved by the service provider, consistent with a gain sharing mechanism set out in the access arrangement (sections 6.19 to 6.28 of the Access Code); and
- the service provider achieving service standards during AA3 that are different to the service standard benchmarks established in the access arrangement, consistent with a service standards adjustment mechanism set out in the access arrangement (sections 6.29 to 6.32 of the Access Code).

Current Access Arrangement

1241. The current access arrangement includes adjustment mechanisms for unforseen events and changes to the Technical Rules. These mechanisms allow for certain costs incurred by Western Power to be carried over from the one access arrangement period to the next and, under the adjustment mechanism applying to changes in the Technical Rules, a carryover of benefits to the third access arrangement period.

1242. The current access arrangement includes an investment adjustment mechanism that allows for the carryover from one access arrangement period to the next period of costs or benefits arising from differences in forecast and actual capital costs associated with differences between forecast and actual new facilities investment. The investment adjustment mechanism applies only to certain classes of new facilities investment:

- new facilities arising from the connection of new generation capacity to the transmission or distribution network from 1 July 2009;
- new facilities investment arising from the connection of new load to the transmission system or distribution system from 1 July 2009;
- new facilities investment in relation to the augmentation of the capacity of the transmission system or distribution system for the provision of covered services from 1 July 2009; and
- new facilities investment undertaken for augmentation of the distribution system under the Regional Power Improvement Program and State Underground Power Program.

1243. The current access arrangement includes a gain sharing mechanism that provides a financial reward to Western Power for out-performance of the forecast of operating expenditure in the second access arrangement.

1244. The current access arrangement includes provision for a deferral of revenue from the second access arrangement period with the deferred amount (escalated for inflation and by the rate of return) to be included in target revenue in the third or subsequent access arrangement periods.

1245. The current access arrangement includes an adjustment mechanism referred to as the “D-factor scheme” under which Western Power is able to carry-over to the third access arrangement period certain costs incurred in the second access arrangement period arising from a deferral of capital projects and from the implementation of demand management initiatives.

1246. The current access arrangement includes a service standard adjustment mechanism that provides a financial reward or penalty depending on Western Power’s actual performance compared to benchmark service standard measures.

1247. Paragraphs 950 to 1033 of this Draft Decision outline the proposed adjustments to target revenue of AA3 in respect of outcomes and events from the current access arrangement.

Proposed Revisions

1248. In the proposed access arrangement revisions, Western Power has maintained the adjustment mechanisms included in the current access arrangement, with the exception of the deferral of revenue. Western Power has not included provisions for deferral of revenue as it is proposing to recoup during AA3 the entire amount of the deferred revenue from the first to second access arrangement periods.

1249. Western Power has proposed a significant change to the service standards adjustment mechanism and a number of amendments to the existing adjustment mechanisms for the gain sharing mechanism and the D-factor.

1250. Western Power has also proposed to amend the manner in which it treats depreciation when establishing the opening capital base for the fourth access arrangement period.

1251. The proposed revisions are discussed further below under Considerations of the Authority.

Public Submissions

1252. Submissions received are discussed below under “Considerations of the Authority”.

Considerations of the Authority

1253. The Authority has considered the proposed revisions to each adjustment mechanism separately as set out below.

Gain sharing mechanism and efficiency and innovation benchmarks

1254. The gain sharing mechanism provides an additional incentive to Western Power to achieve operating cost efficiencies during an access arrangement period as it ensures Western Power retains such benefits for 5 years from when the efficiency is achieved. Western Power is proposing to adjust the gain sharing mechanism to:

- exclude costs relating to superannuation costs for defined benefit schemes, costs associated with non-revenue cap services, licence fees and the Energy Safety Levy from the calculation of the above benchmark surplus as it considers these costs to be outside its control;
- introduce an ex-post growth adjustment to the efficiency and innovation benchmark when calculating the above-benchmark surplus; and
- adjust the above-benchmark surplus formula to cater for the proposed five-year period for the third access arrangement.

1255. Western Power has also proposed to amend the current clause 5.14C which states that in any year in which an above-benchmark surplus is calculated to be a positive value but Western Power fails to meet service standard benchmarks for that year, the above-benchmark surplus for that year is deemed to be zero. Western Power has proposed amending the clause (now renumbered to clause 7.4.3) to reflect the wording of section 6.26 of the Access Code:

> In any year in which an above-benchmark surplus is calculated to be a positive value the above-benchmark surplus does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during this access arrangement period by failing to provide reference services at a service standard at least equivalent to the service standard benchmarks for that year as set out in section 4 of this access arrangement.

1256. The Authority agrees that costs relating to superannuation costs for defined benefit schemes, licence fees and the Energy Safety Levy are outside the control of Western Power and that it is therefore reasonable that such costs should be excluded from the gain sharing mechanism. However, this is subject to Western Power having clearly identified the amounts of these costs in its forecast operating costs for AA3 so that, when the gain sharing mechanism is applied, there is no difficulty in excluding these costs from the original forecast operating expenditure as well as from the actual operating expenditure. The Authority notes that Western Power has provided these details in section 14.3.3 of the proposed revised access arrangement information in table 101 and, on that basis, accepts that sufficient information has been provided to enable the expenditure to be excluded from both forecast and actual operating expenditure. The Authority intends to amend its access arrangement information guidelines to ensure this information is disclosed in the regulatory accounts.

1257. Western Power's reason for excluding the cost of non-revenue cap services from the operation of the gain sharing mechanism is stated as:

> The customer-driven nature of non-revenue cap services means that the operating costs will vary from the forecasts. For example, if we had forecast to undertake 100 units of an activity but were subsequently required to undertake 200 units to meet increased customer demands, costs would be increased and so would revenue. Similarly if customer demand was lower, then costs and revenue will be lower.
>
> If these costs were subject to the GSM it would provide increased incentive to reduce these costs, which could potentially result in a conflict with the need to respond appropriately and effectively to customers' requirements.

1258. The Authority considers that, in principle, this is not unreasonable. However, there needs to be a clearly stated method of attributing costs to the non-revenue cap services that is applied consistently for both the forecast and actual costs. Without a clearly stated method there is a risk that Western Power will over-allocate actual costs to the non-revenue cap services to gain benefits under the gain sharing mechanism. Western Power needs to provide details of the methodology it proposes to use. The Authority also intends to amend its access arrangement information guidelines to ensure this information is disclosed in the regulatory accounts.

1259. As discussed above, Western Power has included scale escalation in its forecast operating expenditure for the third access arrangement period. Western Power proposes that a similar adjustment should be incorporated into the gain sharing mechanism by substituting the forecast scale factors used to derive the efficiency and innovation benchmark for the third access arrangement period, with the actual scale factors when calculating the above-benchmark surplus at the end of the third access arrangement period. Western Power considers it should not be rewarded or penalised for variations from forecast operating expenditure that are attributable to differences in the scale factors driving expenditure (such as customer numbers, line length, number of feeders or zone substation capacity) and that, conversely, customers should not pay more under the gain sharing mechanism because of slower growth.

1260. Western Power's proposed adjustment is similar in nature to its proposals to exclude costs over which it has no control and costs relating to non-revenue cap services discussed above. The Authority considers that, in principle, this is not unreasonable. However, there needs to be a clearly stated methodology for making this adjustment which includes establishing the scaling factors used in the forecast and verifying the actual scale factors. As discussed above, the Authority has not accepted Western Power's proposed scaling factors.

1261. The methodology should set out:

- the underlying assumptions and calculations in relation to scaling factors included in the efficiency and innovation benchmarks approved by the Authority; and
- the method for recalculating the efficiency and benchmarks taking account of actual scaling factors.

Required Amendment 49

Western Power must provide a clearly stated methodology for making this adjustment which is based on the scaling factors approved by the Authority in this draft decision and includes details of how actual scaling factors will be verified.

1262. The Authority accepts the proposed changes to the above-benchmark surplus formula to enable it to be applied for five years as this is consistent with Western Power's proposed target revisions commencement date.

1263. The Authority notes the proposed revision to clause 7.4.3 is consistent with section 6.26 of the Access Code and accepts the proposed revision as reasonable given that it reflects the requirements of the Access Code. However, the Authority notes it is not clear how, in the event that service standard benchmarks are not achieved, it will be determined how and to what extent there is a relationship between cost savings and the underperformance on service standards. Given this issue, an alternative would be to maintain the requirement of the current clause 5.14C, with a new proviso that "unless, or to the extent, that Western Power demonstrates to the satisfaction of the Authority that the above benchmark surplus is unrelated to Western Power failing to achieve the service standard benchmarks".

1264. Whilst the Authority will accept Western Power's proposed amendment on the basis that it complies with the Access Code, further consideration should be given by Western Power to this proposal.

Required Amendment 50

Western Power must amend its proposed revision to clarify how, in the event that service standard benchmarks are not achieved, it will be determined how and to what extent there is a relationship between costs savings and the underperformance on service standards.

Service Standard Adjustment Mechanism

1265. Section 6.30 of the Access Code requires that an access arrangement include a service standards adjustment mechanism, defined under section 6.29 as a mechanism in an access arrangement detailing how the service provider's performance during the access arrangement period against the SSBs is to be treated by the Authority at the next access arrangement review.

1266. Under the SSAM, an amount is added to, or deducted from, the target revenue for each of the transmission system and the distribution system for the next access arrangement period.

1267. Under the SSAM in the current access arrangement (clause 5.24A and 5.24B), each service standard for which there is a service standard benchmark has an accompanying specification of:

- a scheme of penalties and rewards for under-performing or out-performing against the targets established in the access arrangement;
- a target value, which is set equal to the SSB for each year of the second access arrangement period;
- a band around the target value – which is not relevant to the calculation of the reward or penalty for performance that varies from the target value, but which is shown to provide an indication of the expected performance;
- a cap on the 'revenue at risk' for the combined transmission service standards penalties – set at one per cent of maximum transmission revenue, but no cap on the revenue at risk for the combined distribution service standards penalties;[354] and
- no cap on the distribution network 'revenue at risk' during the current access arrangement.

1268. The current access arrangement transmission network SSAM measures relate to:

- Circuit Availability;
- System Minutes Interrupted (meshed network); and
- System Minutes Interrupted (radial network).

1269. The current access arrangement distribution network SSAM measures relate to:

- SAIDI – CBD (Minutes);
- SAIDI – Urban (Minutes);
- SAIDI – Rural short (Minutes);
- SAIDI – Rural long (Minutes);
- SAIDI – CBD (Events);
- SAIDI – Urban (Events);
- SAIDI – Rural short (Events); and
- SAIDI – Rural long (Events).

1270. The SSAM rewards or penalties are derived from the product of the 'service standard difference' (**SSD**) in each year, and the SSAM incentive rates. The SSD is the difference between actual performance on a measure and the target performance. The SSD in the current access arrangement is calculated as follows:[355]

[354] Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 15 - 17.

[355] Ibid.

SSD2009/10 = (SSB2009/10 – SSA2009/10)

SSD2010/11 = (SSB2010/11 – SSA2010/11) - (SSB2009/10 – SSA2009/10)

SSD2011/12 = (SSB2011/12 – SSA2011/12) - (SSB2010/11 – SSA2010/11)

Where:

SSD_t is the service standard difference in year t;

SSB_t is the service standard benchmark in year t; and

SSA_t is the actual service performance in year t.

1271. Western Power incentive rates for the transmission network SSAM for the current access arrangement are set out in Table 117.

Table 117 Transmission network SSAM incentive rates for the current access arrangement and proposed for AA3

	AA2 financial year 2010 – 2012	Proposed AA3 – transitional incentive rate financial year 2013 – 2017	Proposed AA3 – incentive rate financial year 2013 – 2017
Circuit Availability ($ million as at 30 June 2012 per 0.1 per cent)	0.410	0.410384	0.712798
System Minutes Interrupted (meshed network) ($ million as at 30 June 2012 per system minute)	0.082		-
System Minutes Interrupted (radial network) ($ million as at 30 June 2012 per system minute)	0.027		-

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 15 (with ERA conversion to $ million as at 30 June 2012); and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

1272. Western Power incentive rates for the distribution network SSAM for the current access arrangement are set out in Table 118.

Table 118 Distribution network SSAM incentive rates for the current access arrangement and proposed for AA3

	AA2 financial year 2010 – 2012	Proposed AA3 – transitional incentive rate financial year 2013 – 2017	Proposed AA3 – incentive rate financial year 2013 – 2017
SAIDI ($ million as at 30 June 2012 per SAIDI minute)			
CBD	0.240758	0.240758	0.068346
Urban	0.240758	0.240758	0.488756
Rural short	0.008974	0.008974	0.199256
Rural long	0.008974	0.008974	0.062535
SAIFI ($ million as at 30 June 2012 per SAIFI event)			
CBD	11.271870	11.271870	7.691084
Urban	11.271870	11.271870	43.177909
Rural short	0.492460	0.492460	18.879174
Rural long	0.492460	0.492460	8.779766

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 17 (with ERA conversion to $ million as at 30 June 2012); and Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

Summary of Western Power's Revisions

1273. Western Power proposes that the SSAM will apply to the SSAM distribution network target measures SAIDI, SAIFI, and call centre performance, and to the transmission network measure Circuit Availability.

1274. Western Power proposes to change the way that the SSD is calculated, as follows:[356]

> In relation to actual service performance for each year of this *access arrangement period* for each SSAM SSB a reward (a positive amount) or penalty (a negative amount) will be calculated by applying the applicable incentive rate to the relevant Service Standard Difference (**SSD**). The SSD is calculated as follows*:*
>
> a) if SSAt < SSB for SAIDI and SAIFI; or
>
> SSAt > SSB for call centre performance and circuit availability then
>
> SSDt = (SST – SSAt)
>
> b) if SSAt ≥ SSB for SAIDI and SAIFI; or
>
> SSAt ≤ SSB for call centre performance and circuit availability then
>
> SSDt = (SST – SSB)
>
> where:
>
> **SSDt** is the service standard difference in year t;
>
> **SST** is the SSAM target;
>
> **SSB** is the service [minimum] standard benchmark for the SSAM SSBs; and
>
> **SSAt** is the actual service performance in year t with respect to the *SSAM SSBs*.

1275. Western Power also proposes a 'transitional SSAM' to apply to:

- the SAIDI and SAIFI measures (with an additional exclusion in this case for these measures of the interruptions shown to be caused by a fault or other event on the transmission system); and
- the Circuit Availability measure.

1276. Western Power states that the transitional SSAM is 'intended to offset a potential windfall gain or loss arising from the change in the SSAM revenue impact formula from the current access arrangement to AA3'.[357] The SSAM revenue impact formula is proposed to change from the:

- existing current access arrangement which provides a reward for a *positive improvement in net performance* (actual minus target), *compared to that in the year before*; to
- an arrangement where a simple positive *out-performance* (actual minus target) *in any year* is rewarded.

---

356 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 41.

357 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 103.

1277. Western Power proposes the transitional SSAM operate as follows:[358]

> In relation to actual service performance in the financial year ending 30 June 2012 a reward or penalty for each transitional SSAM SSB will be calculated by applying the applicable transitional incentive rate to the relevant Service Standard Adjustment Difference (**SSAdj2012/13**). The SSAdj2012/13 is calculated as follows:
>
> $SSAdj_{2012/13} = SSA_{2011/12} - TSST$
>
> where:
>
> **$SSAdj_{2012/13}$** is the service standard adjustment difference to transition the service standards adjustment mechanism from the previous access arrangement period
>
> **TSST** is the transitional SSAM target
>
> **$SSA_{2011/12}$** is the actual service performance in the financial year ending 30 June 2012 for the transitional SSAM SSBs.

1278. Western Power proposes that:[359]

> The rewards and penalties are applied to the performance year in this access arrangement period (the rewards or penalties for the transitional SSAM SSBs are applied to the financial year ending 30 June 2013) and:
>
> - the reward or penalty for circuit availability will be allocated to the performance of the transmission system;
> - the reward or penalty for SAIDI and SAIFI will be allocated between the performance of the transmission system and distribution system in a fair and reasonable manner except for the reward or penalty for transitional SSAM SSBs which will be allocated to the performance of the distribution system;
> - the reward or penalty for call centre performance will be allocated to the performance of the distribution system.
>
> The rewards and penalties applied to each year as allocated to each of the transmission system and distribution system are summed for each of the transmission system and distribution system.

1279. Western Power further proposes that the sum of the rewards or penalties for the transmission system applied to each year is capped at 1 per cent of the Maximum Transmission Revenue for that year, and at 5 per cent of the Maximum Regulated Distribution Revenue for that year.[360]

Transmission network

1280. The proposed transmission network SSAM service standard targets (**SST**s) are the 50 per cent PoE levels derived from the best fit statistical analysis of the most recent five years of actual monthly performance data (refer to paragraph 1100

---

[358] Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 41.

[359] Ibid.

[360] Ibid.

above for a more detailed description of Western Power's analytical method). The resulting proposed SSAM SSTs are set out at Table 104 above.

1281. Western Power proposed incentive rates for the transmission network SSAM for AA3 are set out in Table 117:

- The Circuit Availability total 'revenue at risk' is half of 1 per cent of the maximum transmission revenue. The incentive rate of $ per 0.1 per cent service standard difference (**SSD**) is the division of this total revenue at risk by the difference in per cent between the SSAM SST and the minimum standard SSB, multiplied by 0.1 per cent.

Distribution network

1282. The proposed distribution network SSAM SSTs are the 50 per cent PoE levels derived from best fit statistical analysis of the most recent five years of actual monthly performance data (an identical approach as for the transmission targets – refer to paragraph 1100 above for a more detailed description of Western Power's analytical method). The resulting proposed SSAM SSTs are set out at Table 106 and Table 107 above.

1283. Western Power proposed incentive rates for the distribution network SSAM for AA3 are set out in Table 118.

1284. The SAIDI and SAIFI incentive rates of $ per minute and $ per event SSD are derived by.

- deriving a 'value of customer reliability' (**VCR**) for each of the Western Australian central business district, urban and rural customer classes – drawing on estimates from a study conducted for VENCorp in Victoria in 2008;
- apportioning the resulting VCR in $/kWh between the two types of events (around half to each type of event respectively);
- determining the average MWh demand/minute for each customer class (to inform the SAIDI incentive rate);
- determining the average MWh demand/event duration for each customer class (to inform the SAIFI incentive rate);
- combining the respective measures to give a $/minute (for SAIDI) and $/event (for SAIFI) incentive rate.

Summary of Submissions

1285. The WAMEU submission commented extensively on the SSAM. Key points included:

- the performance of the transmission network provides an important element of overall delivery of electricity – the removal of transmission measures will provide an avenue for Western Power to avoid a clear assessment of transmission performance;
- the Australian Energy Regulator STPIS incorporates a market impact measure of performance in the incentive scheme to address the outcomes of congestion, and a similar measure should be incorporated in to the SSAM;

- a concern that the service performance targets are set too low and that as a minimum the targets should be set at the historic average;
- a view that the SSAM is relatively low powered, especially in relation to the proposed transmission performance measure;
- concern at the magnitude of the Value of Customer Reliability – as it may be considerably overstated.

1286. Perth Energy submitted that 'performance against... service standards has a direct impact on the utiliity's financial performance through the gain sharing mechanism... [and] that Western Power has failed to meet certain standards set out under the current Access Arrangement and as a result has suffered financially'.[361]

1287. Alinta submitted that it:

- supports the general approach of Western Power in redefining the SSAM that is currently in place for the current access arrangement, for the upcoming AA3 period;
- has a concern that the actual proposed SSAM mechanism is weighted towards rewarding any performance improvement over the whole regulatory period; and
- would support the service standard adjustment mechanism being redefined to ensure that Western Power has the appropriate incentives to meet its services standard benchmarks on a year on year basis.

1288. ERM Power submitted that it does not regard call centre performance as a good indicator for management of the asset base and hence it is not appropriate as a separate revenue incentive target.

Conclusion on Western Power's Proposed Revisions

1289. The Access Code does not provide guidance for the operation of a service standards adjustment mechanism, other than the general requirements of section 6.31 for the mechanism to be:

- sufficiently detailed and complete to enable the Authority to apply the mechanism at the next access arrangement review; and
- consistent with the Code objective.

1290. In the context of the service standards adjustment mechanism, consistency with the Code objective requires that the mechanism provides incentives for a service provider to incur costs efficiently to achieve, and potentially improve on, service standards benchmarks established for the access arrangement period, that provide equal or greater benefits to customers.[362] These costs may be of a capital nature, such as costs of replacing network assets subject to failure, or a non-capital nature, such as costs of undertaking preventative maintenance or employing additional work crews to restore supply more quickly when an outage occurs.

---

361 Perth Energy 2011, Submission, 5 December, p. 7.

362 Efficiency here implies that Western Power should undertake expenditures to improve reference services only up to the point where the marginal costs of service improvement equal the marginal benefits of the service improvements to users of the network.

1291. The Authority has assessed the consistency of the proposed services standards adjustment mechanism with the Code objective by giving attention to:

- the specification and operation of the proposed SSAM and the resultant incentives for actions to achieve and out-perform the proposed SSAM targets;
- the performance criteria proposed to be applied in determining the penalty and reward adjustments, particularly the proposed SSAM targets; and
- the value of incentive rates proposed to be applied in determining penalty and reward adjustments.

1292. These matters are addressed in turn, below.

SSAM incentive formula

1293. Western Power proposes a change in the formula that calculates the annual SSAM reward or penalty for both the transmission and distribution networks.

1294. The existing SSAM SSD was configured such that only an incremental improvement in net performance, compared to that in the year before, was rewarded. Under this approach, performance in any year may be above the SSAM target, but a penalty still applied that year – if the net performance is less than the year before. Conversely, performance may be below the target, but still receive a reward, provided that the net performance shortfall to the target was less than the year before. For example, the formula that applied in the current access arrangement for the second and subsequent years was:

$$SSD_t = (SST_t – SSA_t) - (SST_{t-1} – SSA_{t-1})$$

1295. The proposed method on the other hand aims to institute a simple difference in each year to calculate the SSD:

$$SSD_t = (SST – SSA_t)$$

1296. The Authority considers that neither the existing nor the proposed formula are ideal:

- the existing formula:
  - under-rewards Western Power for most of the access arrangement (**AA**) because the benefit of increasing the level of service is largely captured by consumers;
  - creates incentives to delay improvements in service to late in the AA;
- the proposed formula on the other hand:
  - over-rewards Western Power because the benefit of increasing the level of service is largely captured by it, at the expense of consumers;
  - creates incentives to undertake improvements early in the AA (or else to defer to the start of the next AA).

1297. The Authority has considered two potential alternative formulas as a means to overcome the shortcomings of the above.

1298. The first alternative includes an 'attenuation factor' (**AF**) in the existing formula that conditions the influence of the second term:

$$SSD_t = (SST_t - SSA_t) - \mathbf{AF} * (SST_{t-1} - SSA_{t-1})$$

This is referred to as the ***factor*** approach.

1299. The second alternative accepts the proposed approach as the formula for the SSAM – but with a proviso that the SST be updated every year to incorporate the most recent 12 months of historic data (recalls that the SST is set on the basis of the most recent available 60 months of data). This is referred to as the ***ratchet*** approach.

1300. Analysis by the Authority (**see Appendix 4 for detail**) indicates that both of the alternative formulas are judged to be superior to the existing approach or Western Power's proposed approach – in the sense that there is a more reasonable sharing of the benefits of higher levels of service between Western Power and its customers. The Authority considers that an effective SSAM would set the incentive proportion at about one third of the PV of the benefits to customers of the level of service improvement. This proportion trades off the need to provide an incentive, while at the same time minimising the number of inefficient projects that are undertaken (see **Appendix 4** for a detailed explanation).

1301. The key advantages and disadvantages of each approach are:

- The ratchet approach tends to attenuate the less desirable features of the proposed approach. However, it still tends to over-reward Western Power.
- The factor approach needs to be 'tuned' to an optimal value of 0.6 – but once this is done delivers about one third of the total benefits to Western Power.[363]
- The factor approach also has an advantage over the ratchet approach in that the SSTs are set once, at the beginning of the AA, providing certainty for Western Power. This approach also could remove the need for annual regulatory monitoring of the revisions to the annual targets.

1302. Overall, the Authority considers that the factor formula can be superior to the ratchet formula under most circumstances, and is also superior to either the existing or proposed formulas.

363 The annual factor needs to apply in each year of the AA and in the subsequent AA, so the factor formula needs to apply in every year of the AA. This contrasts with the existing formula, which had the 'simple' formula in the first year of the AA, followed by the 'incremental' formula in the subsequent years.

Required Amendment 51

Western Power should establish the SSAM formula as follows:

$SSD_t = (SST_t - SSA_t) - AF^* (SST_{t-1} - SSA_{t-1})$ for the first and subsequent years of the AA

where:

SSD_t is the service standard difference in year t, and SST_{t-1} is the service standard difference in year t-1;

SST is the SSAM target;

SSA_t is the actual service performance in year t, and SSA_{t-1} is the actual service performance in year t-1, with respect to the SSAM measure;

AF is the 'attenuation factor' that takes the value 0.6.

Transmission network SSAM

SSAM target measures

1303. Western Power proposes that the SSAM for transmission networks in AA3 only apply in respect of the Circuit Availability measure. Western Power proposes to discontinue the SSAM incentives in relation to the System Minutes Interrupted (meshed network) and System Minutes Interrupted (radial network) measures, as these are being discontinued as SSBs. Western Power's rationale for discontinuing these as SSBs, and hence as SSAM measures, is as follows:[364]

> These are measures of the performance of the transmission network rather than the reference service received by transmission-connected customers. The definition of service standard benchmarks relating to network performance (rather than reference services) is not consistent with the requirement of section 5.1 of the Access Code to specify a service standard benchmark for each reference service.

1304. As noted at paragraphs 1113 to 1118 above, the Authority does not consider that the omission of these measures as service standards is justified. The Authority considers these measures provide useful additional information on Western Power's reference service performance. The measure for radial networks is particularly important, as these networks have no redundancy.

---

364 Western Power 2011, *Access Arrangement Information for 1 July 2012 to 30 June 2017*, www.erawa.com.au, p. 90.

1305. The Authority notes that it accepted that there would be neither improvement or deterioration in the transmission network performance over the current access arrangement, given Western Power's proposal:[365]

> Western Power indicates that there are no significant drivers to either improve or relax the service standard benchmarks for the transmission services and benchmarks for the second access arrangement period, and benchmarks are established at the average of the actual performance for 2005/06 to 2007/08.
>
> ...Western Power indicates that the revised forecasts of costs are sufficient to allow for current levels of reliability to be maintained, but that the projected improvements in service standard benchmarks may need to be reviewed.
>
> ...Under this Draft Decision, the Authority is requiring further reductions in forecast non-capital costs. In light of these reductions, the Authority considers that service standard benchmarks for the transmission network are reasonably established to reflect actual performance in the first access arrangement period.

Circuit availability

1306. Western Power proposes that the SSAM service standard target (**SST**) target for Circuit Availability in AA3 should be at a lower standard (97.7 per cent) than in the current access arrangement (98.0 per cent). Western Power states that this expected level of performance should be achievable 50 per cent of the time, when compared to the average actual performance over the last five years.

1307. The Authority notes that the 97.7 per cent level is derived as the Weibull distribution 50 per cent PoE level for the last five years of monthly data (98.2 per cent availability), less a 0.5 per cent reduction to account for the proposed increased level of capital works during the AA3 period.

1308. As noted at paragraph 1107 above, the Authority considers that a 0.5 per cent reduction is not justified, but rather only a 0.2 per cent reduction below the historic performance parameters is justified, given increased capital works anticipated during AA3.

Required Amendment 52

The Circuit Availability target must be set at 98.0 per cent. This is the 50 per cent PoE level derived from the application of a Weibull distribution to the last five years of historic data, but with a reduction of 0.2 per cent included.

System minutes interrupted

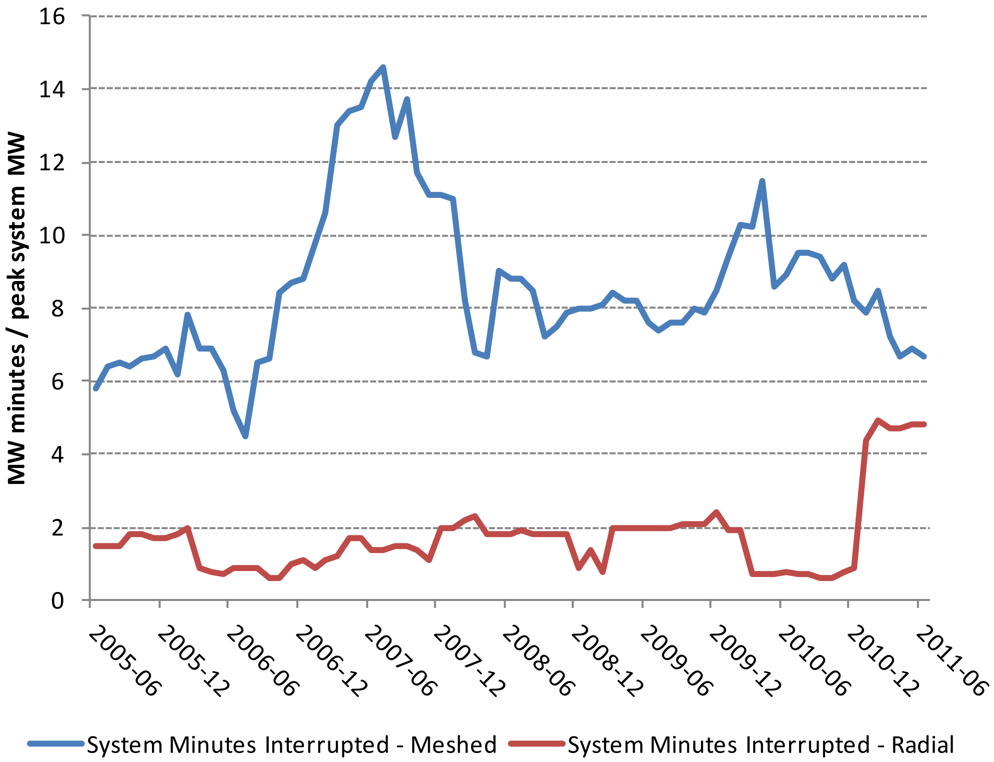
1309. As noted at paragraphs 1113 to 1118 above, the Authority considers that the transmission network service is a key component for the performance of all

[365] Economic Regulation Authority 2009, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, July, pp. 81 and 82.

reference services, and not just for reference services for large customers connected to the transmission network.

1310. The Authority considers that the System Minutes Interrupted (meshed and radial networks) also are important SSAM incentive measures.[366] This is because these incentives will help to ensure that the maintenance of service levels related to elements such as radial networks are not neglected. The Authority notes that based on the unit currently in use – minutes of interruption per system peak MW – performance on these measures recently has been deteriorating for radial networks (Figure 16).

Figure 16 System minutes interrupted – meshed and radial networks



Source: Western Power data

1311. As noted above, security of supply metrics are provided separately for critical and non-critical elements in the Australian Energy Regulator's Service Target Performance Incentive Scheme.[367] The weighting for critical elements can be as high as 20 per cent (Table 119).

[366] Circuit availability reflects the proportion of available time that the network elements are available. System minutes interrupted is a measure of the amount of time in minutes that meshed and radial circuit elements are not available.

[367] Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 43.

Table 119 Transmission incentive measure weightings and 2010 performance for selected National Electricity Market transmission networks

Parameter	Weighting (MAR %)	2010 performance (with exclusions, by relevant unit)
TransGrid		
Circuit availability – transmission line availability	0.20	98.8%
Circuit availability – transformer availability	0.15	98.4%
Circuit availability – reactive plant availability	0.10	95.4%
Loss of supply event frequency > 0.05 (x) system minutes	0.25	3 events
Loss of supply event frequency > 0.25 (y) system minutes	0.10	1 event
Average outage duration - total	0.20	861 minutes
Powerlink		
Circuit availability – critical	0.15	98.7%
Circuit availability – non-critical elements	0.085	98.8%
Circuit availability – peak hours	0.15	98.6%
Loss of supply > 0.2 system minutes	0.15	0 events
Loss of supply > 1.0 system minutes	0.30	0 events
Average outage duration	0.15	779 minutes
ElectraNet		
Circuit availability – total transmission	0.30	99.7%
Circuit availability – critical circuit peak	0.20	99.7%
Circuit availability – critical circuit non-peak	0.0	99.5%
Loss of supply event frequency > 0.05 (x) system minutes	0.10	11 events
Loss of supply event frequency > 0.2 (y) system minutes	0.20	6 events
Average outage duration - total	0.20	130 minutes
Transend		
Transmission circuit availability – critical	0.2	99.5%
Transmission circuit availability – non-critical	0.1	99.4%
Transformer circuit availability	0.15	99.1%
Loss of supply event frequency > 0.01 system minutes	-	9 events
Loss of supply event frequency > 1.0 system minutes	-	2 events
Average outage duration – transmission lines	-	275 minutes

Source: Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 43; Australian Energy Regulator 2011, *Service standard compliance report 2010*, www.aer.gov.au, various network service provider reports.

Required Amendment 53

The System Minutes interrupted (meshed and radial networks) measures must be retained as SSAM incentive measures. The SSAM SST for these measures should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimates).

Loss of supply event frequency

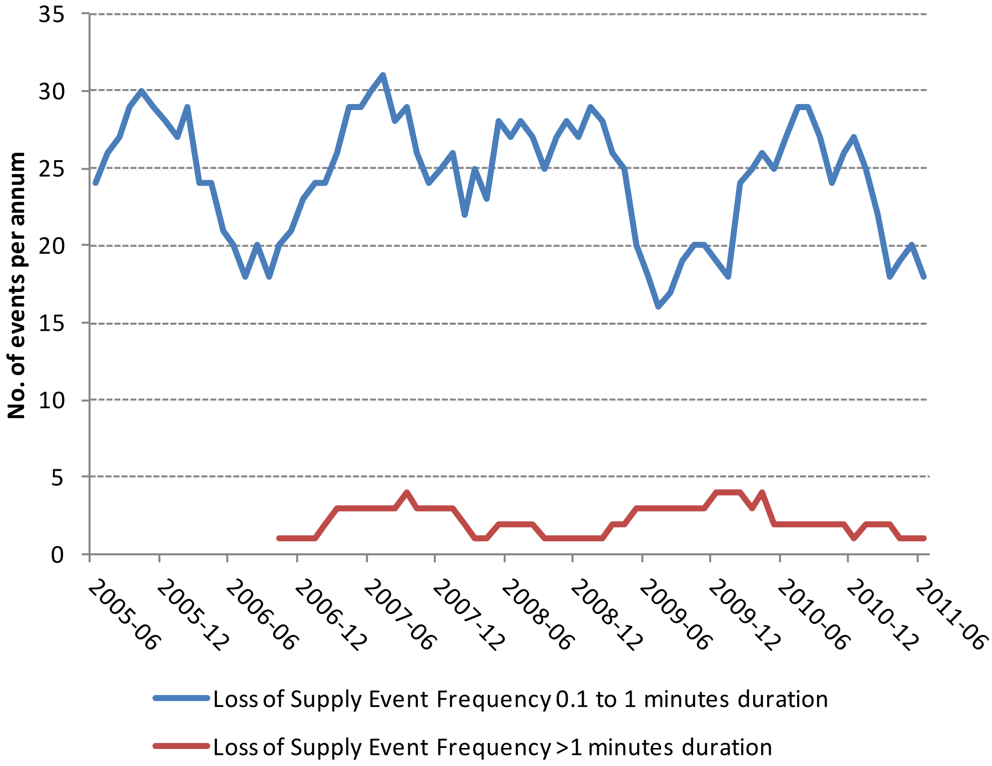
1312. The Authority has given consideration to requiring that unplanned Loss of Supply Event Frequency measures be introduced as SSAM incentive measures.[368] This is because reliability of supply is a key element in network service – customers tend to value reduced frequency of interruptions at close to equal weight to reduced duration of interruptions.[369]

1313. The Authority notes that unplanned Loss of Supply Event Frequency has been variable, with no trend improvement apparent (Figure 17).

368 Circuit availability reflects the proportion of available time that the network elements are available. System minutes interrupted is a measure of the amount of time in minutes that meshed and radial circuit elements are not available.

369 Australian Energy Regulator 2011, *Electricity distribution network service providers: Service Target Performance Incentive Scheme*, www.aer.gov.au, November, p. 11.

Figure 17 Loss of supply event frequency



Source: Western Power data

1314. The Authority also notes that Australian Energy Regulator's transmission network Service Target Performance Incentive Scheme includes this incentive measure. The performance of Western Power would appear to be inferior compared to other transmission network service providers elsewhere in Australia – loss of supply events average around 27 events for Western Power based on the data in Figure 17, whereas it averaged 8 for a sample of network service providers in 2010 (Table 119).

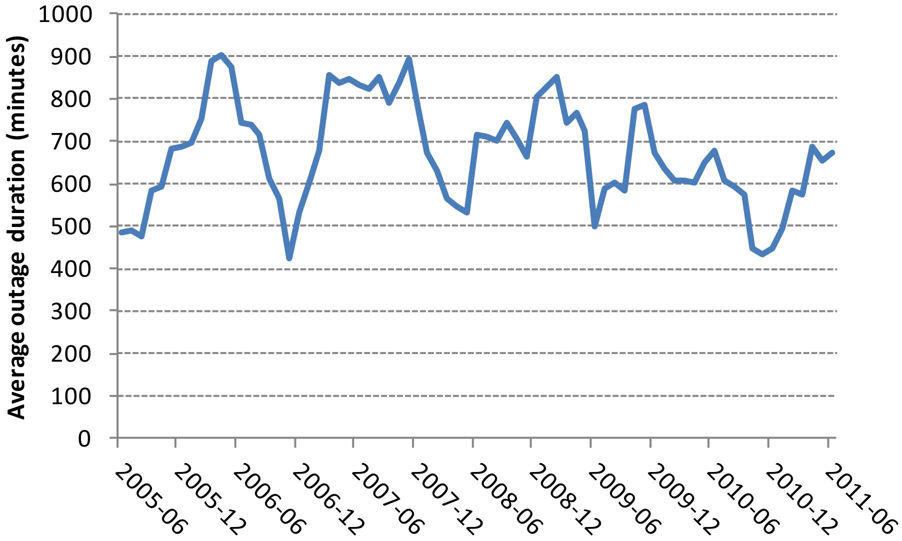
Required Amendment 54

The Loss of Supply Event Frequency measures must be retained as SSAM incentive measures. The SSAM SSTs should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimates).

Average outage duration

1315. The Authority considers that the Average Outage Duration is a key measure of transmission network performance. The Authority notes that performance appears to have been improving in recent times (Figure 18), and is within the range of a selection of network service providers in the east (Table 119). However, it is also clear from Table 119 that Western Power's performance is not at best practice levels.

Figure 18 Average (transmission) outage duration



Source: Western Power data

1316. The Authority therefore considers that further improvement in this measure, or at least maintenance of performance, is desirable.

Required Amendment 55

The Average Outage Duration measure must be retained as SSAM incentive measures. The SSAM SST must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimate).

Transmission incentive rate and weightings

1317. The Authority notes that Western Power has estimated an incentive rate for the transmission network which places 0.5 per cent of the average annual maximum transmission revenue forecast for AA3 at risk.[370] Conversely, Western Power may realise this amount as a reward if performance exceeds the proposed Circuit Availability SST. This appears to be at odds with Western Power's clauses in the proposed access arrangement that:[371]

> 7.5.9 Notwithstanding section 7.5.8 of this *access arrangement*, the sum of the rewards or penalties for the *transmission system* applied to each year is capped at 1% of TR_t for that year as defined in section 5.6.6.

1318. The Authority considers that the proposed amounts leave the transmission networks SSAM relatively underpowered. The Authority notes that the Australian

---

370 This estimate is contained in a spreadsheet provided to the Authority, with the resulting values set out in the proposed access arrangement (see the tables at Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42).

371 Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

Energy Regulator's Service Target Performance Incentive Scheme provides for 1 per cent of revenue to be at risk:[372]

> The maximum revenue increment that a TNSP may earn against its *parameters* and values under this *market impact component* is 2 per cent of the TNSP's *maximum allowed revenue* for the relevant *calendar year*. That is, under this *market impact component*, a TNSP will receive a *financial incentive* which falls within a range of 0 and 2 per cent of the TNSP's *maximum allowed revenue*.

1319. The Authority notes that the Australian Energy Regulator is currently seeking views on its transmission networks Service Target Performance Incentive Scheme. Among the issues being canvassed is the potential to relate more revenue to performance.[373]

1320. While this is an issue for future consideration, the Authority considers that Western Power should increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue – delivering an outcome that aligns with the current approach of the Australian Energy Regulator. In calculating this amount, Western Power will need to take account of the revisions to allowable transmission revenue set out in this draft decision.

1321. Western Power has developed the incentive rate by applying the amount of revenue at risk to the units of difference between the PoE 50 per cent SST and the PoE 97.5 (minimum standard) SSB. The Authority does not have a problem with this general approach. However, the Authority notes that most of the best fit statistical distributions applied to setting the SSB and SST – such as the Weibull distribution – are not symmetric. In these cases, Western Power should apply separate incentive penalty and reward rates so as to evenly span the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively. The reward rates and penalty rates in this case will be asymmetric, with 1 per cent revenue at risk and 1 per cent of revenue available as a reward.

1322. The Authority notes that for the current access arrangement, the penalty/reward rates were derived such that the revenue at risk was divided evenly between the service standards of Circuit Availability and System Minutes Interrupted, reflecting a consideration that these two service standards were of a similar significance.

1323. Western Power has not proposed any weightings in its SSAM proposal as it had only proposed the Circuit Availability measure. However, the Authority is requiring the SSAM now encompass:

- Circuit Availability;
- System Minutes Interrupted (meshed circuits);
- System Minutes Interrupted (radial circuits);
- Loss of Supply Event Frequency (0.1 to 1 minute)
- Loss of Supply Event Frequency (> 1 minute);

[372] Australian Energy Regulator 2009, *Electricity distribution network service providers Service target performance incentive scheme*, www.aer.gov.au, p. 11.

[373] Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 34.

- Average Outage Duration.

1324. The Authority requires that Western Power adopt weightings to allocate the revenue at risk across the various measures (Table 120). In so doing, the Authority has noted the following comments by the Australian Energy Regulator:[374]

> The Australian Energy Regulator has accepted weightings that placed half of the revenue at risk for parameters related to 'security of supply' (i.e. circuit availability) and allocated the remainder equally to parameters related to 'reliability of supply' (i.e. loss of supply) and 'operational response' (i.e. duration of an outage). The Australian Energy Regulator considered this weighting structure to be consistent with the services more highly valued by customers and the objectives of the STPIS.
>
> ...it has been argued that with the aggregate incentive under the scheme set at one per cent of revenue, a parameter specific weighting of less than 10 per cent of the total revenue at risk is too weak to provide an incentive for a TNSP to maintain or improve service performance.

1325. The Authority notes that with these weightings summing to 1, the maximum revenue at risk would be 1 per cent of the maximum transmission revenue.

Table 120 Transmission incentive measure weightings

Parameter	Weighting (MAR %)
Circuit availability	0.2
System Minutes Interrupted (meshed circuits)	0.1
System Minutes Interrupted (radial circuits)	0.2
Loss of supply event frequency (0.1 to 1 minute)	0.1
Loss of supply event frequency (> 1 minute)	0.2
Average outage duration	0.2

Source: Economic Regulation Authority

374 Australian Energy Regulator 2011, *Issues paper Electricity transmission Service target performance incentive scheme*, www.aer.gov.au, p. 28 and p. 30.

Required Amendment 56

Western Power must:

- increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue, taking account of the revisions to allowable transmission revenue set out in this draft decision;
- apply separate incentive penalty and reward rates where non-normal distributions are applied, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively;
- adopt the weightings set out in Table 120 to allocate the revenue at risk across the various measures.

Distribution network SSAM

SSAM target measures

1326. Western Power proposes to retain the SAIDI, SAIFI measures, and to introduce a new Call centre performance measure.

SAIDI and SAIFI

1327. The Authority considers that rewarding or penalising performance against the SAIDI and SAIFI measure targets can provide an appropriate incentive for Western Power to maintain or improve performance on the network. The Authority thus accepts these measures for inclusion in the SSAM.

1328. However, as noted at paragraph 1126 above, the Authority does not consider, on balance, that amendment of the SAIDI and SAIFI measures to include transmission network events is justified. A further issue which supports this view in the context of the SSAM is that there would be considerable additional complexity required to allocate the resulting SSAM incentive rewards or penalties to each of the transmission and distribution network elements. The method for this allocation is not defined in Western Power's proposal – implying a rather open-ended and discretionary approach at this point – that raises concerns about potential cross-subsidies between the networks, and as a result, users. Further additional complexity is introduced by the need for 'transitional' SSTs.

1329. The Authority therefore requires that the SSAM SAIDI and SSAM SAIFI targets be reconfigured to be consistent with the recommendation set out at paragraph 1126 above, and therefore apply to distribution networks only.

1330. Western Power has estimated the SAIDI and SAIDI SSTs based on the 50 per cent PoE analyses of the best fit distribution to the most recent five years (60 months of rolling 12 monthly observations) of relevant performance data (Table 121 and Table 122). The method follows that outlined for the transmission networks at paragraph 1100 above.

1331. The SSBs, and hence SSTs, for these measures had an improving trend over time through the current access arrangement (Table 121 and Table 122 – see also the discussion at paragraphs 1132 to 1133). This reflected that the:[375]

> ...capital and operating expenditures forecast for the second access arrangement period... include provision for "modest but achievable improvements in distribution service performance" and that reliability improvements have been estimated by simulation modelling of the distribution system. Western Power also provides details of planned improvements in reliability (specified as a reduction in SAIDI of 29 minutes for the entire SWIN) to be achieved by 2011/12 as a result of specific capital projects.

1332. The Authority notes that the proposed SSTs for both SAIDI and SAIFI are to be 'stationary' for AA3 – unlike the SSTs that were adopted for the current access arrangement period, which improved in each year of the access arrangement. As noted above, the trend improvement in SSTs in the current access arrangement reflected capital expenditure on service reliability improvement, which customers paid for.

1333. However, the Authority accepts that minimal capital expenditure is proposed for AA3 on service quality improvement. The Authority also notes that there is little evidence or any trend in the historic data for these measures. The Authority therefore considers that the stationary SSTs in each case are acceptable.

---

[375] Economic Regulation Authority 2009, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, www.erawa.com.au, p. 119.

Table 121 Distribution system SAIDI SSAM targets (minutes)

		SWIN total	CBD	Urban	Rural short	Rural long
	Existing arrangement					
1	AA2 year ending June 2010 SSB and SSAM target (D only)[3]	230	38	165	259	612
2	AA2 year ending June 2011 SSB and SSAM target (D only)[3]	224	38	162	253	588
3	AA2 year ending June 2012 SSB and SSAM target (D only)[3]	213	38	153	244	556
	Proposed arrangement					
4	AA3 financial year proposed 'transitional' T&D SSAM target[2]		26	152	243	597
5	AA3 financial year proposed 50% PoE T&D SSAM target[2]	-	28	163	254	616
	Authority estimates					
6	AA3 financial year 50% PoE D only SSAM target[3] – 5 years of data	-	26	152	242	503
7	AA3 financial year 50% PoE D only SSAM target[3] – 3 years of data		22	158	222	600

Note: 1) The definitions of CBD, Urban, Rural Short and Rural Long feeder classification are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR).

2) 'T&D' means transmission and distribution interruptions included in the SAIDI measure.

3) 'D only' means distribution only interruptions included in the SAIDI measure.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 7; Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13; and Authority estimates.

Table 122 Distribution system SAIFI SSBs and SSAM targets (events)

		SWIN total	CBD	Urban	Rural short	Rural long
	Existing arrangement					
1	AA2 year ending June 2010 SSB and SSAM target	2.5	0.24	1.92	3.12	5.00
2	AA2 year ending June 2011 SSB and SSAM target	2.46	0.24	1.89	3.06	4.85
3	AA2 year ending June 2012 SSB and SSAM target	2.41	0.24	1.83	2.98	4.80
	Proposed arrangement					
4	AA3 financial year proposed 'transitional' T&D SSAM target[2]		0.15	1.72	2.76	4.34
5	AA3 financial year proposed 50% PoE T&D SSAM target[2]	-	0.22	1.90	2.91	4.77
	Authority estimates					
6	AA3 financial year 50% PoE D only SSAM target[3] – 5 years of data	-	0.17	1.73	2.75	4.36
7	AA3 financial year 50% PoE D only SSAM target[3] – 3 years of data		0.14	1.61	1.71	4.20

Note: 1) The definitions of CBD, Urban, Rural Short and Rural Long feeder classification are consistent with those applied by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR).

2) 'T&D' means transmission and distribution interruptions included in the SAIFI measure.

3) 'D only' means distribution only interruptions included in the SAIFI measure.

Source: Western Power 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power*, www.erawa.com.au, p. 7; Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 13; and Authority estimates.

1334. Overall, the Authority considers that the method proposed for setting distribution network SSTs is acceptable and will provide appropriate reward or penalty for performance. However, in line with the discussion at paragraph 1131 to 1134, the Authority considers that these distribution network SSTs should be set on the basis of the most recent three years of historic data.

Required Amendment 57

Western Power must:

- adopt revised estimates that remove the transmission network events from the SAIDI and SAIFI measures;
- base the targets on the most recent three years of data – the Authority's estimates of these revised SSTs are set out in row 7 of Table 121 and Table 122 (see also Table 115).

Call centre performance

1335. Western Power also proposes to include a new Call Centre Performance measure as a SSAM measure. The Authority considers that there is merit in this measure, even though it is a process performance measure. The Authority notes that a telephone answering performance measure is a feature of the Australian Energy Regulator's Service Target Performance Incentive Scheme. The Authority accepts the inclusion of this measure as defined in the distribution network SSAM.

Distribution SSAM incentive rates and weightings

1336. Western Power's proposed incentive rates for the distribution network SSAM for AA3 are set out in Table 118.

1337. As noted at paragraph 1283, the SAIDI and SAIFI incentive rates of $ per minute and $ per event SSD are derived by.

- developing a 'value of customer reliability' (**VCR**) for each of the Western Australian central business district, urban and rural customer classes – drawing on estimates from a study conducted for VENCorp in Victoria in 2008;
- apportioning the resulting VCR in $/kWh between the two types of events (around half to each type of event respectively);
- determining the average MWh demand/minute for each customer class (to inform the SAIDI incentive rate);
- determining the average MWh demand/event duration for each customer class (to inform the SAIFI incentive rate);
- combining the respective measures to give a $/minute (for SAIDI) and $/event (for SAIFI) incentive rate.

1338. WAMEU noted in its submission:[376]

> The Western Power proposal includes an approach to developing a cost impact relationship between SAIDI and SAIFI. Western Power uses the VENCorp concept and calculations of Value of Customer Reliability (VCR) to generate this relationship and uses a value of VCR of $62,256/MWh as the appropriate value for the SWIN.

---

[376] WAMEU 2011, Submission, www.erawa.com.au, p. 87.

> The WAMEU is very concerned at the magnitude of this value and its associate Major Energy Users (MEU) has raised similar concerns directly with AEMO. The MEU points to the way the AEMO assessed value of VCR has increased in real terms over the past decade whereas similar values used overseas are much lower and have varied little with time. This raises the concern that the AEMO developed VCR maybe considerably overstated. The ERA is requested to assess VCR in its own right and examine stakeholder views on this issue.

1339. The Authority notes that the Australian Energy Market Operator (**AEMO**) recently reviewed this issue. A report by Oakley Greenwood provided updated estimates of VCRs by customer type and by State, and includes corrections to the Victorian estimates.[377] The same report provides recommendations on escalation approaches.

Required Amendment 58

Western Power must update its estimates of the Value of Customer Reliability to account for the findings of the Oakley Greenwood report – in particular to take account of the revised value of customer reliability estimates and the escalation method.

1340. Aside from that, the Authority accepts that Western Power's proposed approach is consistent with the Code objectives. On this basis, the Authority accepts Western Power's proposed approach.

Required Amendment 59

Western Power must:

- amend the SAIFI incentive rate to be '$ per 0.01 SAIFI event away from the SST';
- retain the proposed SAIDI incentive rate as being '$ per SAIDI minute away from the SST'.

1341. The Authority notes that the incentive rates in this case are derived independently of statistical distributions used to set the minimum standard SSB and the SST. Hence, there is no issue in relation to an asymmetric penalty or reward rate.

1342. The Authority notes that clause 7.5.10 of the proposed AA3 states:[378]

> 7.5.10 Notwithstanding section 7.5.8 of this *access arrangement*, the sum of the rewards or penalties for the *distribution system* applied to each year is capped at 5% of DR_t for that year as defined in section 5.7.6.

[377] Oakley Greenwood 2011, *Valuing Reliability in the National Electricity Market: Final Report*, www.aemo.com.au, p. 32.

[378] Western Power 2011, *Proposed revisions to the Access Arrangement for the Western Power Network*, www.erawa.com.au, p. 42.

1343. For the removal doubt, the Authority notes that clause 7.5.10 implies that 5 per cent of distribution revenue is at risk, and that the total financial incentive (once the potential 5 per cent reward is accounted for) falls within a range of 10 per cent of the distribution revenue. The Authority notes that this is consistent with the Australian Energy Regulator's distribution network Service Target Performance Incentive Scheme, which also provides for the sum of the incentives to lie between + 5 per cent (the upper limit) and - 5 per cent (the lower limit).[379]

1344. Western Power's proposed incentive rate for Call Centre Performance is $60,190 for every 0.1 per cent variation in performance.

1345. This has been calculated as 0.04 per cent of total distribution revenue for each 1 per cent variation in performance, which is consistent with the approach taken by the Australian Energy Regulator in its Service Target Performance Incentive Scheme. Western Power will need to adjust the incentive rate to reflect the changes to total distribution revenue set out in this Draft Decision.

1346. The Authority also notes that the distribution applied to Call Centre Performance for the purposes of establishing the SSB and SST is a Weibull distribution, which is not symmetric around the SST. Asymmetric rewards and penalty rates would improve the allocation of incentives.

Required Amendment 60

Western Power must:

- adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Draft Decision;
- apply separate incentive penalty and reward rates to the Call Centre Performance incentive, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively.

The "D factor" scheme

1347. The D-factor mechanism provides for the recovery in the next access arrangement period of operating expenditure that is incurred by Western Power as a result of deferring a capital expenditure project or in relation to demand-management initiatives.

[379] Australian Energy Regulator 2009, *Electricity distribution network service providers Service target performance incentive scheme*, www.aer.gov.au, p. 11.

1348. Western Power has proposed retaining the D-factor in its current format but has proposed that claims for deferred expenditure can only be made in relation to projects included in the D-factor Project List (provided to the Authority as confidential material) or the Transmission Network Development Plan. The current access arrangement requires that any expenditure claimed to have been deferred must have been included in Western Power's forecast capital expenditure in its revised access arrangement information or supporting documentation and in the Authority's allowed capital expenditure for the access arrangement period.

1349. Western Power considers the proposed revision will ensure there is documented evidence of any planned or potential capital investment that may be deferred by demand management or alternative options to network augmentation. Western Power notes that the D-factor Project List and the Transmission Network Development Plan include capital projects that are not certain enough to have been included in the AA3 expenditure forecasts at the time of preparation. Western Power considers that linking the D-factor to these lists helps remove the bias towards capital investment solutions created by the investment adjustment mechanism.

1350. In its submission, Synergy considers that D-factor projects and any associated funding should be treated no differently to any other new facility to enable Western Power to provide covered services. Synergy has also queried whether the D factor scheme is an adjustment that is allowed for under the Access Code.

1351. The D-factor scheme was introduced in the second access arrangement review. Questions were raised at that time as to whether such a scheme was permitted as it was not one of the adjustments contemplated under Chapter 6 of the Access Code.

1352. In its final decision in relation to the second access arrangement, the Authority accepted that a scheme such as the proposed D-factor scheme may have efficiency benefits in the provision of network services. The Authority considered the potential efficiency benefits of the proposed D-factor scheme arose due to the limited incentive that a service provider may have to seek efficiency in capital costs where an increase in non-capital costs is necessary to achieve this efficiency. For example, a saving of $100 in capital expenditure during an access arrangement period relative to the forecast for that period will give rise to a "reward" to the service provider of an amount equal to the rate of return and depreciation allowance on the amount of $100, say $10 where the rate of return is 6 per cent and where depreciation of the capital asset is at $4 per annum. However, under a conventional scheme of regulation, any (above-forecast) non-capital costs that would be incurred by the service provider in achieving the efficiency gain in capital costs are not recoverable. So, if additional non-capital costs of $20 were required to achieve the $100 saving on capital costs, the service provider would be worse off by delaying the capital project even though the substitution of non-capital costs for capital costs would have been efficient.

1353. Many non-network alternatives (including demand management programs) involve substituting non-capital costs for capital investment in a network to resolve network constraints. In circumstances where opportunities for non-network alternatives are not identified and addressed in cost forecasts for an access arrangement period, the potentially limited incentive to substitute non-capital costs for capital costs may create disincentive to developing and implementing efficient non-network alternatives. This disincentive is increased by efficiency incentive schemes, as any additional non-capital costs incurred by the service provider may not only be unrecoverable, but may also reduce incentive payments that may otherwise accrue to the service provider from other, unrelated, efficiency gains.

1354. The D-factor scheme included in the current access arrangement seeks to address the disincentive to implement non-network alternatives to capital projects in resolving network constraints. In the final decision for the current access arrangement the Authority took the view that section 6.2 of the Access Code is not exclusive as to the specific methods of price control (including adjustment mechanisms) and sections 6.1, 6.2 and 6.4 provide discretion as to the form of price control provided it meets the objectives in section 6.4 and complies with Chapter 6. The Authority considered it was appropriate to allow such adjustments under the access arrangement where there is a clear consistency with the objectives for a price control and the Code objective. On that basis, the Authority accepted that the proposed D-factor scheme was consistent with the requirements of the Access Code.

1355. On the particular provisions of the D-factor scheme, the Authority considered that the scheme as set out in Western Power's proposals for the second access arrangement, did not adequately constrain the operation of the scheme to circumstances where the deferral of capital expenditure or the implementation of demand management schemes is economically efficient. The original proposal required that there be an "approved" business case for the D-factor scheme to apply to an amount of expenditure; there was no explicit requirement for the business case to demonstrate efficiency in the relevant costs.

1356. The Authority determined that the operation of the D-factor scheme should be subject to any amount of operating expenditure or capital expenditure satisfying requirements of the Access Code that normally apply in determining amounts of costs that may be recovered through network tariffs. The Authority required the scheme to provide for operation of the D-factor scheme to be subject to demonstration, to the Authority's satisfaction, that:

- any amount of operating expenditure satisfying the requirements of sections 6.40 and 6.41 of the Access Code, as relevant; and
- any amount of capital expenditure satisfying the requirements of section 6.51A of the Access Code.

1357. Western Power has now proposed that claims for deferred expenditure can only be made in relation to projects included in the D-factor Project List (provided to the Authority as confidential material) or the Transmission Network Development Plan. The D-factor Project List includes capital projects that are not certain enough to have been included in the expenditure forecasts for the third access arrangement.

1358. The Authority is of the view that the D-factor Project List facilitates operation of the D-factor scheme as it assists assessment of whether a capital project has actually been deferred. However, the Authority considers that it would be inconsistent with the objectives of section 6.4 of the Access Code and the Code objective for this list to include any projects that are not included in the current forecast of capital expenditure and that have been assessed under section 6.51 as meeting the tests under the Access Code for inclusion in the "forward-looking and efficient costs of providing covered services".

1359. The Authority therefore considers this proposed amendment moves the D-factor scheme away from its original purpose which was to address the limited incentives that a service provider may have to seek efficiency in capital costs where an increase in non-capital costs is necessary to achieve this efficiency. The current scheme applies only to deferrals of capital expenditure which have been included in the forecast of costs taken into account in determination of target revenue for the access arrangement period.

1360. The Authority notes that Western Power has not claimed any expenditure in relation to the D-factor scheme and has given further consideration to Synergy's submission that D-factor projects and any associated funding should be treated no differently to any other new facility to enable Western Power to provide covered services.

1361. The D-factor scheme was approved at the second access arrangement to remove an apparent disincentive for service providers to seek efficiency in capital costs where an increase in non-capital costs was necessary to achieve the efficiency on the basis that, otherwise, such non-capital costs could not be recovered. However, under the Access Code there is provision for the service provider to apply at any time under 6.76 and 6.41 to have these costs recovered. On reflection, the Authority considers that the existing provisions of the Access Code in relation to the approval of non-capital costs as set out in sections 6.40, 6.41 and 6.76 provide sufficient mechanisms to enable Western Power to claim any such costs as are contemplated by the proposed D-factor scheme.

1362. Given that section 6.76 enables a service provider to apply at any time for such costs to be determined, the Authority does not consider that it is necessary for an additional mechanism such as the proposed D-factor scheme, and agrees that any such cost should be treated no differently to any other expenditure to provide covered services.

Required Amendment 61

The D-factor scheme must be removed from the proposed revised access arrangement.

Deferral of Revenue

1363. As discussed above, the Authority has determined that only part of the deferred revenue should be recovered during AA3. Consequently the current adjustment mechanism in relation to the recovery of deferred revenue should be retained in the proposed revised access arrangement.

Required Amendment 62

The current adjustment mechanism in relation to the recovery of deferred revenue must be retained in the proposed revised access arrangement with the deferred amounts of revenue to be updated to:

$48.6 million ($ as at 30 June 2012) for transmission services; and

$365.2 million ($ as at 30 June 2012) for distribution services.

Treatment of Depreciation in Establishing the Opening Capital Base for the fourth access arrangement

1364. When establishing the opening capital base for the second and third access arrangement period, depreciation was based on the values forecast for the first and second access arrangement periods respectively. Forecast depreciation for the second and third access arrangement periods therefore took account of any differences between actual and forecast depreciation in the preceding period.

1365. Western Power proposes to continue this methodology in relation to investment categories subject to the IAM. However, for investment categories not subject to the IAM, Western Power proposes to use actual depreciation to establish the capital base at the commencement of the fourth access arrangement. The impact of this is that any difference between actual and forecast depreciation during the third access arrangement period will not be adjusted for in forecast depreciation for the fourth access arrangement period.

1366. Western Power claim that “using actual depreciation provides the business an incentive to spend capital expenditure efficiently where service is not affected” and that “using actual depreciation to establish the AA4 capital base meets the Access Code objective as it promotes economically efficient investment in the network by providing an incentive to reduce capital expenditure”.

1367. The Authority does not agree that such an amendment is required and is concerned it would increase the incentive to over forecast capital expenditure. The current methodology ensures the service provider target revenue over time recovers all depreciation relating to actual expenditure. The proposed change could potentially result in Western Power recovering a higher level of depreciation through target revenue than is actually incurred.

Required Amendment 63

The proposed revised access arrangement must be amended to remove the proposed change to the treatment of depreciation in establishing the opening capital base for the fourth access arrangement.

TRIGGER EVENTS

Access Code Requirements

1368. Under sections 5.34 of the Access Code, an access arrangement may specify one or more trigger events. A trigger event is defined in the Access Code as a set of one or more circumstances specified in the access arrangement, the occurrence of which requires a service provider to submit proposed revisions to the Authority under section 4.37 of the Access Code.

1369. Under section 5.35 of the Access Code, trigger events may be either proposed by the service provider or included in an access arrangement by the Authority.

1370. Under section 5.36 of the Access Code, before determining whether a trigger event is consistent with the Code objective, the Authority must consider:

- whether the advantages of including the trigger event outweigh the disadvantages of doing so, in particular the disadvantages associated with decreased regulatory certainty; and
- whether the trigger event should be balanced by one or more other trigger events.

Current Access Arrangement

1371. The current access arrangement includes a broad specification of trigger events under clause 8.1:

> 8.1 Any significant unforeseen development which has a materially adverse impact on the service provider and which is:
>
> (i) outside the control of the service provider; and
>
> (ii) not something that the service provider, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and
>
> (iii) an event the impact of which is so substantial that the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

1372. Clause 8.2 of the current access arrangement requires that Western Power must submit proposed revisions to the Authority within 30 business days after a trigger event has occurred.

Proposed Revisions

1373. Western Power has proposed increasing the number of days by which it must submit proposed revisions to the Authority after a trigger event has occurred from 30 business days to 90 business days.

Submissions

1374. None of the submissions made to the Authority on the proposed access arrangement revisions address trigger events.

Considerations of the Authority

1375. The Authority accepts the proposed increase in time for Western Power to submit proposed revisions to the Authority following a trigger event appears reasonable. In the absence of any public submissions on this proposed revision the Authority accepts Western Power's proposed amendment.

STANDARD ACCESS CONTRACT

Access Code Requirements

1376. A standard access contract sets out the terms and conditions under which a user may obtain access to a reference service at the reference tariff. Section 5.1(b) of the Access Code requires that an access arrangement include a standard access contract for each reference service. An access arrangement may contain a single standard access contract in which the majority of terms and conditions apply to all reference services and the other terms and conditions apply only to a specified reference services.

1377. The requirements for standard access contracts are set out in sections 5.3 to 5.5 of the Access Code:

5.3 A standard access contract must be:

(a) reasonable; and

(b) sufficiently detailed and complete to:

(i) form the basis for a commercially workable access contract; and

(ii) enable a user or applicant to determine the value represented by the reference service at the reference tariff.

5.4 A standard access contract may:

(a) be based in whole or in part upon the model standard access contract, in which case, to the extent that it is based on the model standard access contract, any matter which in the model standard access contract is left to be completed in the Access Arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model standard access contract; and

(ii) section 5.3; and

(iii) the Code objective;

and

(b) be formulated without any reference to the model standard access contract and is not required to reproduce, in whole or in part, the model standard access contract.

{Note: The intention of this section 5.4(b) is to ensure that the service provider is free to formulate its own standard access contract which complies with section 5.3 but is not based on the model standard access contract.}

5.5 The Authority:

(a) must determine that a standard access contract is consistent with section 5.3 and the Code objective to the extent that it reproduces without material omission or variation the model standard access contract; and

(b) otherwise must have regard to the model standard access contract in determining whether the standard access contract is consistent with section 5.3 and the Code objective.

Current Access Arrangement

1378. The current access arrangement includes a standard access contract (the "electricity transfer access contract") that applies to all of the reference services offered under the access arrangement.

Proposed Revisions

1379. In the proposed access arrangement revisions, Western Power has maintained the single electricity transfer access contract for all reference services (**proposed electricity transfer access contract**). The proposed electricity transfer access contract includes revisions made for the purposes of clarifying existing provisions as well as substantive changes to, or additions to, the contract.

1380. The principal revisions proposed for the electricity transfer access contract include:[380]

- removal of clause 3.1(d) which had been used for the provision of a modified service within the electricity transfer access contract. Western Power has proposed that this service be provided as a non-reference service to ensure that the electricity transfer access contract is only used for access to reference services;
- removal of the reference to 'de-energisation' in clause 3.6 to ensure that a connection point is not unintentionally deleted from an electricity transfer access contract when the intent was to simply de-energise the connection point (e.g. where a user seeks a temporary interruption of service to be followed by a subsequent re-energisation which may include situations where the user no longer has a contract with the customer at the connection point);
- amendment of the definition of 'payment error' in clause 8.6 to cover all of the situations covered by the clause, and the insertion of new clauses 8.6(f) and 8.6(g) to allow clause 8.6 to operate correctly; and
- amendments to clause 9, including insertion of a new clause 9(c) which will require users, on receipt of a written request by Western Power, to increase the level of security where the existing security no longer equals the charges for two months services, and to clause 9(e) to manage security in situations where a parent company's circumstances change.

1381. Details of these proposed revisions are provided below under "Considerations of the Authority".

Submissions

1382. Submissions on the terms of the proposed electricity transfer access contract are addressed below under "Considerations of the Authority".

380 Proposed revised access arrangement, Appendix A.

Considerations of the Authority

1383. In considering the proposed revised access arrangement, the Authority has considered whether, partly in light of practical experience, the terms and conditions of the electricity transfer access contract that are proposed to continue, are consistent with the requirements of the Access Code.

Basis of Proposed Standard Access Contract

1384. Synergy's submission states that "It is important to recognise the Standard Access Contract represents the minimum standards and terms for an access contract". This statement is not correct as a service provider and a potential user are free to negotiate on any terms of access to a service (including terms which differ from a standard access contract). However, in the event of a dispute over the terms of an access contract for a reference service, the arbitrator must not make an award specifying terms of an access contract that are inconsistent with the standard access contract for the reference service in the access arrangement (section 10.21 of the Access Code).

1385. Section 5.3 of the Access Code requires a standard contract to be:

(a) reasonable; and

(b) sufficiently detailed and complete to:

(i) form the basis of a commercially workable access contract; and

(ii) enable a user or applicant to determine the value represented by the reference service at the reference tariff.

1386. In its submission Synergy also questions whether the Standard Access Contract proposed is based on section 5.4(a) or (b) of the Access Code, but notes it appears to have been developed under section 5.4(b) of the Access Code i.e. formulated without any reference to the model standard access contract and therefore not required to reproduce, in whole or in part, the model standard access contract. Synergy notes that, if this is the case, then section 5.5(b) of the Access Code applies when making a determination on the proposed standard access contract and requests Western Power to make this clear in its proposed revised access arrangement.

1387. The Authority confirms that it does have regard to the model standard access contract in determining whether the standard access contract is consistent with section 5.3 and the Access Code objective as required under section 5.5 of the Access Code. However, this is a requirement placed upon the Authority and is not something which needs to be referred to by Western Power in its proposed revised access arrangement.

1388. Landfill Gas and Power submits that the terms of the contract should have regard to fitness for purpose. Using itself as an example, Landfill Gas and Power notes that it is a small generator-retailer operating four small power stations supplying fewer than 100 customers and submits that the insurance obligations should be commensurate with this, rather than the same as apply to much larger entities. Landfill Gas and Power submits that, as electricity retailers are arms-length users with no practical functionality to affect the network, the network contract should reflect this through less onerous conditions.

1389. Section 5.1(b) of the Code requires an access arrangement to include a standard access contract for each reference service, the note to section 5.1(b) suggests an access arrangement may contain a single standard access contract in which the majority of terms and conditions apply to all reference services. The requirement of the Access Code is that the standard access contract is reasonable and sufficiently detailed to form the basis of a commercially workable access contract. There is no requirement to provide different levels of standard access contracts for the same reference service. However, under section 2.4A of the Access Code, parties may negotiate an access contract on any terms, including terms which differ from a standard access contract.

Removal of Modified Service (clause 3.1(d))

1390. Western Power has proposed removal of clause 3.1(d) which had been used for the provision of a modified service within the electricity transfer access contract. For AA3 Western Power has proposed that such services will be provided as non-reference services to ensure that the electricity transfer access contract is only used for access to reference services.

> 3.1(d) Notwithstanding clause 3.1(a)(i), Western Power* may provide the User* with a Modified Service* for a Connection Point* stipulated in Part 4 of Schedule 3 (if any) until:
>
> (i) the date set out in Part 4 of Schedule 3 for the Connection Point*; or
>
> (ii) until the events or works (as applicable) set out in Part 4 of Schedule 3 for that Connection Point* are completed to Western Power*'s satisfaction (acting as a Reasonable and Prudent Person*)

1391. The inclusion of this clause in the electricity transfer access contract was approved by the Authority in the current access arrangement. At the time, the Authority observed that there was nothing in clause 3.1(d) that altered any obligation arising under either the Access Code or the access arrangement for Western Power to undertake necessary works or meet conditions for the provision of a contracted service. Further, the provision for a modified service implies that, in practise, a user and Western Power will need to agree on provision of a service other than a reference service, or agree on provision of a service on terms and conditions other than those contained in a standard access contract. On that basis, the Authority considered that clause 3.1(d) was consistent with section 5.3 of the Access Code.

1392. Conversely, deleting clause 3.1(d) does not alter any obligation arising under either the Access Code or access arrangement for Western Power to undertake necessary works or meet conditions for the provision of a contracted service. On this basis, the Authority accepts the deletion of the clause.

Deletion of a Connection Point (clause 3.6)

1393. Clause 3.6 of the proposed electricity transfer access contract provides for the user to request deletion of a connection point from the contract. Clause 3.6 also sets out the circumstances in which Western Power is obliged to comply with the request. Western Power's proposed revisions to clause 3.6 are set out below with the proposed new text underlined.

3.6 Deletion of a Connection Point*

(a) The User* may give notice to Western Power* seeking to delete a Connection Point* from this Contract* where:

(i) the Customer* in relation to the Connection Point* has made a transfer request under the Customer Transfer Code*; or

(ii) the Connection Point* will be added to another Access Contract* by some other means to that stipulated in clause 3.6(a)(i); or

(iii) the Facilities and Equipment* in respect of the Connection Point* will be permanently Disconnected* from the Connection Point*.

(b) If the User* seeks to permanently Disconnect* any Facilities and Equipment* at a Connection Point*, then the notice under clause 3.6(a) must be given to Western Power*:

(i) for Generating Plant* at a Connection Point*, at least 6 months before the planned Disconnection*; and

(ii) for Consuming* plant at a Connection Point*, at least one month before the planned Disconnection*.

(c) If Western Power* receives a notice from the User* under clause 3.6(a), then it must notify the User* that it accepts the deletion, and the date that the deletion takes effect, if;

(i) Western Power* has successfully processed a Customer* transfer request in relation to the Connection Point* under the Customer Transfer Code*; or

(ii) the Connection Point* has been added to another Access Contract* by some other means; or

~~(iii) Western Power* has De-energised* the Connection Point* under this Contract* or a law*; or~~

(~~iv)~~(iii) the Facilities and Equipment* in respect of the Connection Point* have been permanently Disconnected* from the Connection Point*,

otherwise Western Power* may notify the User* that it rejects the deletion.

(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

Proposed amendments to Clause 3.6(a)

1394. Western Power has expanded clause 3.6(a) to clarify the grounds upon which deletion of a Connection Point may be requested. In effect, the amendments to clause 3.6(a) will make that clause consistent with clause 3.6(c) which sets out the circumstances in which Western Power must accept a deletion request.

1395. Synergy has submitted that the Customer Transfer Code only permits a retailer to make a customer transfer request. This issue has been discussed with Western Power which accepts Synergy's observation and agrees that clause 3.6(a)(i) should be amended to read as follows:

> "a transfer request has been made in relation to the Customer* for that Connection Point* under the Customer Transfer code"

1396. In its proposal for clause 3.6 Synergy has deleted Western Power's proposed new clauses 3.6(a)(i), (ii) and (iii). Synergy has not provided any specific reasoning for doing this. The Authority considers Western Power's proposed amendment clarifies the circumstances in which a user can request deletion of a connection point and accepts the proposed amendment by Western Power.

1397. Western Power has proposed the removal of the reference to 'de-energisation' in clause 3.6 to ensure that a connection point is not unintentionally deleted from an electricity transfer access contract when the intention was to simply de-energise the connection point (e.g. where a user seeks a temporary interruption of service to be followed by a subsequent re-energisation).

1398. Western Power has noted in its access arrangement information that deletion and de-energisation are separate concepts. Western Power describes de-energisation as a temporary interruption or cessation of electricity supply, whereas deletion is a permanent cessation. Western Power considers there should only be a permanent removal of a Connection Point from a User where the Connection Point has been transferred to another user, or where the equipment at the Connection Point has been permanently disconnected. Western Power considers that, as long as a Connection Point still exists (i.e. it has only been de-energised rather than the equipment at that point removed), then the costs which are still incurred in maintaining the equipment need to continue to be allocated to the User. Western Power considers that if a User wishes to cease paying charges in respect of a Connection Point because it no longer has a contract with the Customer or Generator at that Connection Point, then it must either have that Connection Point transferred to another user or have it deleted (not simply de-energised).

1399. In its submission, Synergy did not directly respond to this point but has proposed, as set out at paragraph 1403 below, the inclusion of a requirement that where the user has requested the deletion of the Connection Point because the User no longer has a contract with a customer or a generator at the Connection Point, then Western Power is required to do so within the timeframe required under the electricity transfer access contract, or any other contract or law.

1400. The Authority notes that, under the proposed access contract terms and conditions, even if a contract between a retailer and a customer ceases for some reason, the connection point will remain subject to the access contract of the retailer until it is transferred, added to another access contract or is disconnected. The Authority considers this to be reasonable and that connection to the network should attract some charging for network services. The retailer can either apply for permanent disconnection or transfer to another retailer.

1401. The Authority observes that, in the normal course of events, there would never be a Connection Point that is not subject to the access contract for a retailer or other network user. However, if for some reason a Connection Point exists where there is no contract with a retailer, then that connection point would revert to the "default supplier" retailer under section 59 of the Act.

Synergy Submission

1402. In its submission Synergy has raised other concerns with clause 3.6. Synergy submits that, in its practical experience, the terms of the proposed standard access contract dealing with deletion of a connection point do not place a positive obligation on Western Power to effect such a deletion in accordance with the legal framework, knowledge of or a request by the retailer. Synergy notes that it has suffered and continues to suffer financial loss and damages when Western Power permits a person to use a Connection Point subject to Synergy's access contract and does not act on a notification from Synergy to delete an entry or exit Connection Point from Synergy's access contract. Synergy states it has also suffered the converse of this scenario where a Connection Point has been deleted from its access contract without Synergy issuing any notification or instructions to do so under its access contract, thus creating issues between Synergy and the customer under Synergy's supply contract with the customer. Synergy does not consider these incidents have promoted the economically efficient operation and use of the network and network services. If the situation is not satisfactorily addressed, the additional costs and liabilities that Synergy incurs due to the acts or omissions of the network operator will need to be passed on to all consumers.

1403. Synergy also considers it is not reasonable for a retailer to be liable for an act or omission of the network operator, including inefficiencies in the network operator's internal processes, to effect the removal of a Connection Point from the retailer's access contract. In addition, Synergy considers that existing clause 3.6 of the standard access contract is not sufficiently detailed and complete to form the basis of a commercially workable access contract. Synergy considers this lack of clarity exposes retailers to loss or damage resulting from the acts or omissions of the network operator and, to prevent this, considers the standard access contract should place a positive obligation on the network operator to effect a deletion only in accordance with the Customer Transfer Code or the retailer's instructions.

1404. Synergy has proposed the following changes to clause 3.6 which it considers addresses the issues it has raised and recognises the operation of photovoltaic systems connected to the network:

3.6 Deletion of a Connection Point*

(a) The User* may give notice to Western Power* seeking to delete a Connection Point* from this Contract* ~~where~~:

~~(i) the Customer* in relation to the Connection Point* has made a transfer request under the Customer Transfer Code*; or~~

~~(ii) the Connection Point* will be added to another Access Contract* by some other means to that stipulated in clause 3.6(a)(i);~~

~~or~~

~~(iii) the Facilities and Equipment* in respect of the Connection Point* will be permanently Disconnected* from the Connection Point*.~~

(b) If the User* seeks to permanently Disconnect* any Facilities and Equipment* at a Connection Point*, then the notice under clause 3.6(a) must be given to Western Power*:

(i) for Generating Plant* with a capacity greater than 30 kVA at a Connection Point*, at least 6 months before the planned Disconnection*; and

(ii) for Consuming* plant) (and Generating Plant* up to and including 30kVA) at a Connection Point*, in accordance with the applicable "model service level agreement" or "service level agreement" under the Metering Code* (as amended or substituted from time to time) ~~at least one month before the planned Disconnection*.~~

(c) If Western Power* receives a notice from the User* under clause 3.6(a), then it must ~~notify the User* that it accepts the deletion, and the date that the deletion takes effect, if~~;

(i) where Western Power* is required to effect ~~has successfully processed~~ a Customer* transfer request in relation to the Connection Point* under the Customer Transfer Code* - delete the Connection Point* by the time the transfer is to take place under the Customer Transfer Code*; or

(ii) where the Connection Point* is required to be ~~has been~~ added to another Access Contract* by some other means – delete the Connection Point* as contemplated by that means; or

(iii) where the User* has requested the deletion of the connection Point* because the User* no longer has a contract with a Customer* or a Generator* at the Connection Point* - delete the Connection Point* by the time within which Western Power* is required to De-energise* the Connection Point* under this Contract*, any other contract or a Law*; or ~~the Facilities and Equipment* in respect of the Connection Point* have been permanently Disconnected* from the Connection Point*, otherwise Western Power* may notify the User* that it rejects the deletion~~.

(iv) where the User* has given Western Power* a notice under clause 3.6(a) that complies with clause 3.6(b)(i) – by the time of the planned Disconnection*; or

(v) where the User* has given Western Power* a notice under clause 3.6(a) that complies with clause 3.6(b)(ii) – by the time the Disconnection* is required to take place under the applicable "model service level agreement' or "service level agreement' under the Metering Code*

and as soon as practicable notify the User* that it accepts the deletion, and the date that the deletion takes effect, otherwise notify the User* as soon as practicable that Western Power* rejects the deletion.

(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

(f) Notices under clause 3.6 may be issued and delivered in accordance with processes determined by mutual agreement of the Parties* (for example, without limitation, Build Pack* communications)."

1405. The Authority addresses each of Synergy's points below.

Removal of Connection Points without consent of User

1406. The explicit protection of users against an unrequested deletion of a Connection Point was raised during the second access arrangement review. As set out in its further final decision, the Authority determined that clause 3.6 should be amended to include this protection and Western Power agreed to insert clause 3.6(d):

> 3.6(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

1407. The Authority considers clause 3.6(d) adequately protects Users as Western Power is only able to delete a Connection Point where requested by a User, or if required by law (the Customer Transfer Code).

1408. If Synergy does not consider Western Power is complying with these provisions, then any such instances need to be resolved between Synergy and Western Power. It is not a matter to be resolved through development of the electricity transfer access contract.

1409. The Authority also notes that under clause 3.6(e), if Western Power wilfully breaches clause 3.6(d) it is liable to the User for any damage suffered and the exclusion of liability for Indirect Damages does not apply. If Western Power breaches clause 3.6(d) in circumstances which are not a Wilful Default it would still be liable for the losses suffered by the User but subject to the limitation of liability provisions set out in the electricity transfer access contract.

Failure to Delete Connection Points in response to User's request

1410. The Authority notes that clause 3.6(c) clearly provides that Western Power must accept a deletion of a Connection Point if:

- Western Power has successfully processed a Customer transfer request in relation to the Connection Point under the Customer Transfer Code; or
- the Connection Point has otherwise been added to another Access Contract; or
- the equipment at the Connection Point has been permanently disconnected.

1411. The Authority also notes that clause 4.10 of the Customer Transfer Code obliges Western Power to process transfer requests and sets out the timeframes within which this is to be done.

1412. The Authority considers the existing provisions are adequate both in terms of setting out the circumstances under which Western Power is required to delete Connection Points and ensuring that Western Power complies with such requests.

1413. As the Authority noted in paragraph1406 above in relation to removal of connection points without the consent of the user, if Synergy considers Western Power has failed to delete a connection point in response to a request from Synergy, then any such instances need to be resolved between Synergy and Western Power. It is not a matter to be resolved through development of the electricity transfer access contract.

Synergy's Proposed Revisions to Clause 3.6

1414. Each of Synergy's proposed drafting amendments to clause 3.6 is considered below.

Clause 3.6(a)

1415. Synergy's proposal is considered at paragraph 1394 above.

Clause 3.6(b)

1416. In its proposed amendment to clause 3.6(b), Synergy has proposed generators with capacity up to and including 30 kVA should not be required to give six months notice for permanent disconnection of a connection point. Instead, it proposes that the notice period for generators up to and including 30 kVA and for all consuming plant should be linked to the applicable service level agreement.

1417. The Authority has discussed this proposed amendment with Western Power which has advised that it does not consider this amendment is appropriate as not all users are required to adopt the model service level agreement. A different service level agreement under the Metering Code may be negotiated between the parties which may not necessarily set out timeframes for deletion of Connection Points. Furthermore, Western Power notes that the model service level agreement sets out the timeframes for undertaking a supply abolishment but does not set out the timeframes for requesting the abolishment.

1418. The Authority agrees that it is inappropriate to link the timeframes in clause 3.6(b) to service level agreements and that it will provide greater clarity to include the timeframes in the electricity transfer access contract as is currently the case.

1419. The Authority has discussed the notice period for generators with capacity up to and including 30 kVA with Western Power. Western Power advised that it does not oppose a 30 day notice period for such generators providing they are being used to offset load at a connection point (as is the case for a residential photovoltaic system). However, it considers that, where the generator is not offsetting load then a notice period of at least 6 months before the planned disconnection of the generator is required to allow Western Power sufficient time to reconfigure or augment the network, as required, as a result of the generator's permanent disconnection.

1420. The Authority requires an amendment to be made to the electricity transfer access contract such that a one month notice period for permanent disconnection is required for generators up to and including 30 kVA, providing the generator is offsetting load.

Clause 3.6(c)

1421. Clause 3.6(c) sets out the requirements for Western Power to notify users when it accepts a request for deleting a connection and the date the deletion takes effect. Synergy has proposed additional wording which it considers clarifies the requirements and has included an obligation for Western Power to notify users "as soon as practicable".

1422. The Authority has discussed Synergy's proposed amendments with Western Power. Western Power considers the current version of the clause provides adequate clarity and that the amendments proposed by Synergy are unnecessarily complex and in some cases incorrect. Western Power also considers that the standard proposed by Synergy of "as soon as practicable" is too high. It considers the current position (that is, notification is given within the time required by law or within a reasonable time[381]) is appropriate and that it would be wrong to elevate the obligations in relation to deletion of Connection Points above the various other obligations and activities that Western Power has in relation to its network.

1423. Western Power has also made the following points:

- The transfer process is adequately accommodated by the electricity transfer access contract's existing wording and Synergy's proposed changes to clause 3.6(c)(i) confuse issues and are not consistent with the Customer Transfer Code.
- Synergy's proposed amendment to clause 3.6(c)(ii) is incorrect as the test is not whether a Connection Point is required to be added to another access contract but whether it has in fact been added.
- It is not appropriate to cross-refer to service level agreements under the Metering Code as Synergy has done in its proposed clause 3.6(c)(v), because not all users have service level agreements with timeframes linked to clause 3.6(c)(v) and, where there are such agreements, clause 3.6(c)(v) deals with a wider range of issues than is required to be dealt with in service level agreements under the Metering Code.

1424. The Authority considers Western Power's proposed drafting of clause 3.6 adequately sets out the circumstances in which users may give notice to Western Power to delete a Connection Point and the process Western Power must follow. However, the Authority considers that Synergy's request that Western Power be expressly required to notify users "as soon as practicable" is not unreasonable, and considers the addition of the word "reasonably" before practicable would take account of any reasonable processes Western Power is required to carry out before notifying users. Therefore, the Authority agrees that the closing statement to clause 3.6(c) should be amended to read as follows:

> " as soon as reasonably practicable, otherwise Western Power* may notify the User* that it rejects the deletion as soon as reasonably practicable."

Clause 3.6(f)

1425. Synergy has proposed adding an additional clause relating to processes for issuing and delivering notices under clause 3.6. In Western Power's view, such a clause is unnecessary having regard to that process already being dealt with in clause 35. Western Power also considers a specific provision that the parties may agree a process for the issuing of notices under clause 3.6 is not required, on the basis that parties may always agree such a process and it is unnecessary to provide further for this.

---

381 Western Power considers that, as clause 3.6(c) is silent in respect of timeframes, notification must be given in accordance with requirements of law (as required by clause 37.1 of the electricity transfer access contract) or, where no timeframe is prescribed, then notification must be given within a reasonable time based on case law (eg N C Seddon and M P Ellinghaus, *Cheshire and Fifoot's Law of Contract*, Ninth Australian Edition, paragraph 21.19, p. 1027).

1426. The Authority agrees the standard access contract already contains sufficient provisions in relation to notices and does not consider it necessary or desirable to include any further provisions.

Summary

Taking account of the matters discussed above, the Authority requires clause 3.6 to be amended as follows:

3.6 Deletion of a Connection Point*

(a) The User* may give notice to Western Power* seeking to delete a Connection Point* from this Contract* where:

(i) ~~the Customer* in relation to the Connection Point* has made~~ a transfer request has been made in relation to the Customer* for that Connection Point* under the Customer Transfer Code*; or

(ii) the Connection Point* will be added to another Access Contract* by some other means to that stipulated in clause 3.6(a)(i); or

(iii) the Facilities and Equipment* in respect of the Connection Point* will be permanently Disconnected* from the Connection Point*.

(b) If the User* seeks to permanently Disconnect* any Facilities and Equipment* at a Connection Point*, then the notice under clause 3.6(a) must be given to Western Power*:

(i) for Generating Plant*, excluding generating plant up to and including 30 kVA which is being used to offset load, at a Connection Point*, at least 6 months before the planned Disconnection*; and

(ii) for Consuming* plant and generating plant up to and including 30 kVA which is being used to offset load, at a Connection Point*, at least one month before the planned Disconnection*.

(c) If Western Power* receives a notice from the User* under clause 3.6(a), then it must notify the User* that it accepts the deletion, and the date that the deletion takes effect, if;

(i) Western Power* has successfully processed a Customer* transfer request in relation to the Connection Point* under the Customer Transfer Code*; or

(ii) the Connection Point* has been added to another Access Contract* by some other means; or

~~(iii) Western Power* has De-energised* the Connection Point* under this Contract* or a law*; or~~

(~~iv)~~(iii) the Facilities and Equipment* in respect of the Connection Point* have been permanently Disconnected* from the Connection Point*,

as soon as reasonably practicable, otherwise Western Power* may notify the User* as soon as reasonably practicable that it rejects the deletion.

(d) Subject to the Customer Transfer Code*, Western Power* must not delete a Connection Point* other than in accordance with a notice given by a User* under clause 3.6.

(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

Required Amendment 64

The Authority requires that clause 3.6 be amended as set out in paragraph 1426 above.

Notification of permanent reconfigurations (clause 3.7)

1427. Clause 3.7 sets out requirements for amending Connection Point data. Western Power has not proposed any amendments to this clause, however, the Authority notes the numbering of its sub-clauses contains errors which require amendment.

1428. In its submission, Synergy has raised a concern in relation to clause 3.7(g).[382] Synergy submits that it is necessary to clarify and restrict the application of clause 3.7(g) in the proposed standard access contract to circumstances in which Western Power has implemented a permanent reconfiguration only where it is legally entitled to do so. Synergy considers the current drafting of the clause results in it being applicable to situations where Western Power has physically undertaken a permanent reconfiguration, irrespective of whether Western Power did so in accordance with the regulatory regime.

1429. Synergy considers that in these situations it is not reasonable or commercially workable for Synergy and other retailers to commercially suffer the consequences and liabilities of a permanent reconfiguration that has been implemented by Western Power contrary to law and the regulatory regime. Synergy notes that its practical experience has highlighted that an amendment is necessary and proposes that clause 3.7(e) be amended as follows:

3.7(e) Subject to clause 3.7(h), where Western Power*, <u>in accordance with its legal rights and obligations,</u> causes a Permanent Reconfiguration* of the Network* which results in the information contained in the Contract Database* having to be updated…"

1430. The Authority has discussed the matters raised by Synergy with Western Power. Western Power notes Synergy has not provided any specific examples to illustrate the concerns it has which makes it difficult for Western Power to respond. Western Power also notes that clause 37.1 of the electricity transfer access contract already requires Western Power to comply with applicable laws so, in its view, it is unnecessary to repeat such requirements elsewhere in the standard access contract.

[382] Western Power's proposed revised electricity transfer access contract has incorrectly numbered this as clause 3.7(e) which is the reference Synergy has used in its submission. The correct clause number is 3.7(g).

1431. The Authority agrees that it would be more helpful if Synergy provided specific examples to which Western Power could respond but this appears to be an operational issue which does not need to be considered for the purposes of approving the standard electricity access contract. The Authority also agrees that clause 37.1 adequately ensures that Western Power complies with applicable laws and that the amendment to clause 3.7(e) proposed by Synergy is unnecessary.

Limitation on Liability (clause 6.2(e), 19.2 and 19.5)

1432. Western Power has not proposed any amendments in relation to liability but submissions from Synergy and the Office of Energy have raised a number of issues.

1433. Synergy considers there is a lack of clarity and certainty in the standard access contract on a retailer's liability for actions resulting in direct damages. Synergy submits that it is not reasonable, and is contrary to section 5.3 of the Code, for the standard access contract to impose liabilities on a retailer for matters which are clearly beyond a retailer's control but which are within Western Power's control. This is especially in circumstances where the network operator has been negligent or approved the connection of equipment and facilities to its network which results in damage. Synergy submits that this principle is not clearly articulated in the standard access contract, and the practical effect of the omission is to make retailers liable for outcomes that are beyond their control.

1434. Synergy submits that the most efficient way to manage risk is to assign it to the party best placed to manage it. Therefore, Synergy submits that the specific liability provisions in the standard access contract, in particular under clauses 6.2, 19.2 and 19.5, need to be reviewed in the context of assigning risk to the party best able to manage it. Synergy considers that in this respect the standard access contract does not represent the minimum conditions for Users and, in fact, treats a retailer no differently to a generator.

1435. The Authority observes that, as set out at paragraph 1384 above, Synergy's view that the standard access contract should represent the minimum conditions for users is not strictly correct. There is also no requirement under the Access Code to provide separate standard access contracts for retailers and generators.

1436. Synergy notes that clause 6.2(e) purports to give retailers some relief by allowing Western Power to establish a connection contract with the controller of the equipment which Western Power approved to connect to its network. However, Synergy states that Western Power has declined to establish these connection contracts, with the result that the retailer is liable for the actions of the controller, despite Western Power inspecting and approving the controller to connect equipment to the network. Synergy considers this practice by Western Power also requires retailers to police the activities of controllers of the network, including inspecting and making sure controllers connect to the network in accordance with the connection approval provided by Western Power.

1437. Synergy submits it is not reasonable for Western Power to have no liability in circumstances where it inspects and approves the connection of equipment and facilities to the network.

1438. Consequently, Synergy requests the Authority to make the following amendments to clause 6.2(e) of the standard access contract:

6.2(e) For the avoidance of doubt, if the User* is in breach of clause 6.2(a), then the User* is liable for, and must indemnify Western Power* pursuant to clause 19.2 against any Direct Damage* caused by, consequent upon or arising out of the acts and omissions, negligent or otherwise, of the Controller* to the extent that the acts or omissions, negligent or otherwise, of the Controller* are attributable to that breach, unless the Controller* has entered into a Connection Contract* with Western Power* <u>or Western Power has refused to enter into a Connection Contract* with the Controller*.</u>

1439. Synergy made similar submissions in respect of clause 6.2 at the time of the second access arrangement review. In response to these submissions the Authority required the inclusion of an indemnity from Western Power to Users (which is set out in clause 6.2(g) of the electricity transfer access contract) against costs incurred by Users in taking action against Controllers to procure compliance with the electricity transfer access contract.

1440. The Authority has discussed Synergy's concerns with Western Power. Western Power considers that the inclusion of clause 6.2(g) at the last access arrangement review sufficiently meets both the concerns raised by Synergy during the current access arrangement and those raised in Synergy's current submission, which in substance are the same.

1441. Western Power refers to the Authority's reasons relating to the current access arrangement amendment:

- The Model Access Contract requires the User to ensure (and provides that the User is liable for) compliance by the Controller of Connection Points over a specified capacity - specifically those Connection Points referred to in clause A3.38 of the Model Access Contract, which corresponds to clause 6.1 of the current electricity transfer access contract (**ETAC**).
- The Authority accepted that, given the terms of the Model Access Contract, it was consistent with the Code objectives for the User to take responsibility for those Connection Points.
- For Connection Points not referred to in clause 6.1 the Authority determined that the User was only required to take action to enforce compliance of the Controller of those Connection Points if Western Power provided the indemnity in clause 6.2(g).

1442. Western Power also considers the amendment to clause 6.2(e) proposed by Synergy is unclear and unworkable. In particular, it is unclear how the test would be applied and at which point refusal would be deemed to have occurred. Western Power gives an example of whether it would be treated as having refused to enter into a contract with a controller if, despite the User wanting Western Power to do so, the Controller refuses to enter into the relevant contract.

1443. The Authority agrees with Western Power that Synergy's proposed amendments to clause 6.2(e) are unclear and unworkable, and will result in ambiguity.

Limitations on Warranty Obligations (clause 18.1)

1444. Western Power has not proposed any revisions to clause 18.

1445. Synergy submits that the standard access contract does not make it clear what should occur in circumstances where a User is in breach of its warranty or representations as a direct result of Western Power breaching its obligations.

Synergy considers that in such circumstances it is not reasonable for a retailer to be liable to Western Power and for Western Power to exercise its rights under clause 27.2 of the standard access contract. Synergy proposes that, in order to clarify the rights of the parties in such circumstances, clause 18.1 should be amended as follows:

> 18.1 If the User* is in breach of the warranty and representation in clause 18.1(a) of this Contract* as a direct result of a breach of the Application and Queuing Policy* or the Code* by Western Power then Western Power may not exercise its rights under clause 27.2 of this Contract* other than to notify the User* of the User*'s Default and the User* will not be liable to Western Power for the breach."

1446. The Authority has raised this matter with Western Power. In its response, Western Power noted that it would seem improbable that a court would find a User to be in breach of a warranty where that breach is caused by a breach of the Access Code or the Applications and Queuing Policy, by Western Power but it has no objection to dealing with the matter in the electricity transfer access contract if it makes the issue clearer. Western Power has proposed this could be achieved by amending clause 18.1(a)(i) to read as follows:

> "the User* has complied with the Applications and Queuing Policy* in the Access Arrangement and the requirements in the Code* in respect of its Application* under the Access Arrangement* <u>provided that the User* will not be taken to be in breach of this warranty because of a failure by the User* to comply with the Applications and Queuing Policy* or the Code* which is the direct result of a breach by Western Power* of the Applications and Queuing Policy* or the Code*"</u>

1447. Western Power considers clause 18.2(a)(i), where Western Power provides the same warranty to the User, as the User provides to Western Power in clause 18.1(a)(i), should be similarly amended.

1448. Clauses 18.1(a)(i) and 18.2(a)(i) should be amended as follows:

> Clause 18.1(a)(i)
>
> "the User* has complied with the Applications and Queuing Policy* in the Access Arrangement and the requirements in the Code* in respect of its Application* under the Access Arrangement* <u>provided that the User* will not be taken to be in breach of this warranty because of a failure by the User* to comply with the Applications and Queuing Policy* or the Code* which is the direct result of a breach by Western Power* of the Applications and Queuing Policy* or the Code*"</u>
>
> <u>Clause 18.2(a)(i)</u>
>
> "Western Power* has complied with the Applications and Queuing Policy* in the Access Arrangement and the requirements in the Code* in respect of its Application* under the Access Arrangement* <u>provided that Western Power* will not be taken to be in breach of this warranty because of a failure by Western Power* to comply with the Applications and Queuing Policy* or the Code* which is the direct result of a breach by the User* of the Applications and Queuing Policy* or the Code*"</u>

Required Amendment 65

Clause 18.1(a)(i) and 18.2(a)(i) must be amended as set out in paragraph 1448 above.

Compensation for Loss Caused by the Network Operator (clause 19)

1449. Western Power has not proposed any revisions to clause 19.

1450. In its submission Synergy is seeking an addition to section 19 to specify Western Power's liability (to pay compensation to users) for losses caused by Western Power and claims the current definition of "Direct Damage" is too narrow and one-sided. Synergy argues that as Western Power is in the best position to manage its risk and its operations when providing services, it should be liable for its actions in relation to the provision of those services.

1451. Synergy has drafted a new clause which it considers should be included in clause 19:

19.4 Western Power Liability

(a) <u>If Western Power* is negligent or commits a Default* under this Contract* it must:</u>

<u>(i) repay to the User* any Customer Pass Through Amounts* which the User* is not reasonably able to recover from its Customers* because of the negligence or Default* of Western Power* or because of delay by Western Power* in rectifying or otherwise addressing the negligence or Default*;</u>

<u>(ii) reimburse the User's* reasonable costs, including legal costs, of any reasonable action taken for the purposes of recovering from its Customers* the Customer Pass Through Amounts* referred to in clause 19.4(a)(i);</u>

<u>(iii) reimburse the User's* reasonable Operational Costs* of addressing and mitigating the impacts on its business operations arising from, or in connection with, the negligence or Default* of Western Power*;</u>

<u>(iv) compensate the User* for any loss or damage, including Indirect Damage*, the User* suffers or incurs as a result of, or arising from, any reduction in cash flow caused by Western Power's* negligence or Default*;</u>

<u>(v) reimburse the User* for all expenses and charges (including any Indirect Damage* or other damages, penalties, fines or interest) that the User* incurs as a result of or in connection with a claim by a Customer* under the Competition and Consumer Act*, which the User* is not reasonably able to avoid because of the negligence or Default* of Western Power*;</u>

(vi) not enforce any rights it may have against the User* or the Indemnifier* in respect of a User's Default* that arises due to the negligence or Default* of Western Power*.

(b) The User* must notify Western Power* if the User* intends to take legal action to recover amounts under clause 19.4(a)(i) or to take or not take legal action to defend a claim by a Customer* in relation to clause 19.4(a)(iv) and provide all reasonable details of the actions the User* proposes to take.

(c) Western Power* must, within [7 days] of receiving notification under clause 19.4(b), advise the User* whether Western Power* wishes to take over the proposed legal action, in which case the User* and Western Power* must work co-operatively to enable Western Power* to take over such legal action on behalf of the User*.

Customer Pass Through Amounts* means amounts paid by the User* to Western Power* under the Contract* which the User* would, in the normal course of its business, pass on to its Customers* and the exclusion of Indirect Damage* does not apply.

Operational Costs* means amounts paid by the User* to Western Power* under the Contract* which the User* would, in the normal course of its business, pass on to its Customers* and the exclusion of Indirect Damage* does not apply.

Competition and Consumer Act* means the *Competition and Consumer Act 2010* (Cth).

1452. Synergy requested a similar amendment during the current access arrangement. In its draft decision for the current access arrangement the Authority did not accept that the liability of Western Power for damages as proposed by Synergy was reasonable. The electricity transfer access contract explicitly limits damages recoverable by a person to direct damage other than where a party commits fraud. This is a deliberate scheme and such limitation of liability is quite common for access contracts relating to large infrastructure with multiple users where indirect losses could be substantial (e.g. if a breach causes power disruption for a period of time, the consequential or indirect damage could include potentially large financial losses, such as lost profits and damage to goodwill for each affected business).

1453. Synergy's proposal would make two exceptions to this limitation – fraud (an existing exception) and deletion of a connection point. Under Synergy's proposal, Western Power would be liable for indirect damages arising from the deletion of a connection point other than in accordance with clause 3.6 of the proposed electricity transfer access contract, whether this be negligent or deliberate.

1454. The Authority considers that making Western Power liable for indirect losses arising from the deletion of a connection point, where such deletion occurs as a result of negligence, is inconsistent with the other provisions of the electricity transfer access contract. The Authority does, however, consider that such liability is reasonable where the deletion of a connection point other than allowed for under clause 3.6 is wilful or deliberate.

1455. The Authority determined that Western Power should be liable for indirect losses arising from the deletion of a connection point, where the deletion of a connection point otherwise than allowed for under clause 3.6 is wilful or deliberate. Western Power agreed to insert clause 3.6(e):

3.6(e) If Western Power* commits a breach of clause 3.6(d) in circumstances that constitute Wilful Default* it is liable to the User* for any damage caused by, consequent upon or arising out of the Wilful Default*. In this case, the exclusion of Indirect Damage* in clause 19.3 does not apply.

1456. The Authority considers the existing provisions in the electricity transfer access contract regarding compensation for losses are reasonable and therefore meet the requirements of section 5.3 of the Code.

Cap on Liabilities

1457. Both the Office of Energy and Synergy have raised issues in relation to clause 19.5 which limits the liability of Western Power's and users to a maximum amount. This limit is the lesser of $80 million and a formula based on the User's number of connection points within each of five categories of connection points.

1458. In its submission, the Office of Energy notes that, in practice when applied to retailers, the formula is unlikely to return a value of less than $80 million. The Office of Energy states that, as no sub-limits are set for a User's liability in respect of individual events at the various types of connection points, the maximum liability accruing to a User in respect of a liable event at any of its connection points will always be the annual liability cap set by clause 19.5(b), namely, $80 million.

1459. The Office of Energy submits that if a retailer wishes to effectively pass through all liabilities associated with all customer connections, it would need to ensure all its customers were insured to the upper limit of potential liability for damage to the network, being $80 million (or as otherwise determined under 19.5(b)). The Office of Energy considers this is not feasible for small connections and while retailers may require small customers to indemnify them, they will not check for insurances in most cases. In any event, the Office of Energy considers it would be unrealistic to expect many small customers to insure against an $80 million liability.

1460. The Office of Energy notes that, for small connections, it appears retailers enter into supply contracts on the assumption that the plausible liability associated with those customers is much less than $80 million. However, the Office of Energy considers retailers have shown themselves unwilling to make the same assumption in relation to small customers with renewable energy systems, because grid connection of small renewable generation equipment is a relatively new phenomenon.

1461. The Office of Energy considers that Western Power should be encouraged to estimate the upper limit of the damage to the network that may arise from a single liable event for the main different classes of connections, including bi-direction service customers and that these estimates should then be used to establish sub-limits to liability for individual events in each connection class, under the electricity transfer access contract.

1462. Synergy also made submissions on clause 19.5 and noted that, in its experience, insurers will only extend cover to retailers for the acts or omissions of the retailer only and not those of third parties. Synergy has been unable to determine how a retailer, through its own actions, could cause $80 million dollars of damage to the network, especially under a regime where the network operator has the obligation to inspect, maintain and approve the connection of equipment to the network. In the context of assigning risk to the party best able to manage it, Synergy does not understand the economic basis that Western Power has used to determine this value. Therefore, in light of clause 6.2(e), Synergy submits that it is reasonable for the standard access contract to specify a different maximum cap for generators and retailers and that the Authority, in assigning risk to the party best able to manage it, must be satisfied with the methodology used to determine these amounts. It is Synergy's preference that the methodology is subject to public consultation as part of the Authority's determination of the proposed revised access arrangement.

1463. In response to these submissions, Western Power stated:

- Synergy's submission does not acknowledge the fact that the way the cap is determined is by aggregating the amounts referred to in clause 19.5(b)(ii). The $80 million is a further level of protection for the User.
- Synergy's submission implies that the User should not take responsibility for the acts or omissions of their customers. However such a lack of responsibility would be inconsistent with the structure of the Western Australian electricity industry which is based on Users having contracts with the end-use customers. The Users therefore need to be responsible for the acts or omissions of the end-use customers because only the Users have the contractual right to control how the end-use customers behave. Western Power cannot regulate what end-use customers do and does not have contractual rights to claim damages from the end-use customers if they do not comply with the standards noted in the ETAC.
- The liability allocation in the ETAC (i.e. where the User takes responsibility for their customers) is the same as that in other jurisdictions where the infrastructure owner does not have a contractual relationship with the customer – specifically, New South Wales (Jemena Access Arrangement) South Australia (Envestra Access Arrangement) and Queensland (Envestra and APT Access Arrangements). Furthermore the liability cap ($80 million) is more generous to the User than the caps which apply in these jurisdictions.
- In the APT Access Arrangement for its Queensland Distribution Network the User gives an uncapped indemnity against any damages/losses flowing from the User's breach of its agreement with the Service Provider and against any damage to the network caused by the User or any of its customers (clause 14.5).
- In the Jemena Access Arrangement, the User provides various indemnities to the Service Provider, including in respect of overrun and failure to cease take of gas when required by the Service Provider (both of which are matters within the control of the end-use customer). There is no cap on liability for these indemnities.
- Each of the above arrangements and the liability regimes within them have been approved by the AER within the last 24 months.
- The potential certainly exists for a User to cause Western Power $80 million in damage over the course of a year – noting that the $80 million is an annual aggregate cap. If over the course of a year there were a large number of incidents due to a User's poor management of the actions of its customer base, this scenario could well arise. That said, Western Power considers that a User who was effectively managing the behaviour of its end-use customers should not find itself in this position.
- In respect of Synergy's assertion that it is reasonable for the access contract to specify a different maximum cap for generators and retailers, Western Power notes that clause 19.5(b)(ii) does specify different caps for generators and retailers. However where a party to the ETAC is both a generator and a

retailer then these individual subcaps need to be combined, which is what is effected by clause 19.5(b)(i).

- Synergy itself proposed a cap of $60 million at the time of the second Access Arrangement Review. There is no developed reasoning in Synergy's submission as to why this cap is inappropriate, other than the clear indication that Synergy does not wish to take responsibility for the acts or omissions of its customers.

1464. In response to the Office of Energy's submission that Western Power should be encouraged to estimate the upper limit of damage to the network which could arise from a single event for the main different classes of connections and then use this to determine sub-limits for individual events, Western Power responds as follows:

- It is not aware of any evidence that the current liability regime is a barrier to entry. There is no evidence similar regimes in the New South Wales, Queensland and South Australian gas industries act as a barrier to entry;
- A variation to the liability caps, and consequent increase to Western Power's risk profile, will in turn impact the cost of its insurance and this will need to be reflected in tariffs;
- If Western Power is required to absorb the cost of damage to its network then, to the extent insurance proceeds are not available, this cost of repair should also be reflected in tariffs. Otherwise, there is an adverse impact on Western Power's return due to the acts of Users and Western Power is being provided with no additional recompense for absorbing this risk (as compared to what would be expected to occur in a competitive market).
- Western Power is not aware of any regulatory regimes where sub-limits for individual classes of events are determined in the manner contemplated.
- Further, Western Power is of the view that a regime where liability limits are set by reference to specific events is both unwieldy and impractical (which presumably accounts for why such regimes are not, to our knowledge, used).
- To determine a liability limit for a single event in the different classes of connection would require Western Power to undertake a comprehensive risk assessment of the maximum potential damage that could arise in each class of connection and then determine an appropriate liability cap for that class. This would require a comprehensive analysis of the type of equipment within such connections and a determination of the possible events that could arise and cause such damage. This would in turn require both engineering analysis and also analysis with Western Power's insurers and brokers. Further the analysis is not simply a matter of considering the potential impacts arising from the operations of generators on the one hand and customers on the other. The potential impact of a generator will depend upon the type of generator it is and its location in respect of the rest of the network (which will in turn determine the potential consequences of an event affecting it). This may also be the case with customers. Therefore it will not be possible to identify one reliable cap per type of event.

1465. The Authority considered clause 19 at the last access arrangement review. In its final decision the Authority determined that the maximum liabilities proposed by Western Power were unreasonable in that, for users that are retailers with many connection points, the maximum liability of the user may be an amount in excess of any reasonably conceivable level of damages to the network or Western Power. As a result the Authority did not consider Western Power's proposal was consistent with the requirements of the Access Code and required there be a cap on the maximum liability of users.

1466. However, the Authority agrees with Western Power that there have been no significant change in circumstances since the last review that would justify a change to the upper limit of liability.

Western Power Invoices (clause 8.1 and 8.6)

1467. Western Power has proposed amendment of the definition of 'payment error' in clause 8.6 to cover all of the situations covered by the clause, and the insertion of new clauses 8.6(f) and 8.6(g) to allow clause 8.6 to operate correctly. The proposed revisions are as follows:

8.6(f) Where a Payment Error* is an error as a result of which the amount set out in a Tax Invoice* is less than what it would have been had the error not been made, the Payment Error* will be taken to have occurred on the Due Date* of the Tax Invoice*.

8.6(g) Where a Payment Error* is an error as a result of which the amount set out in a Tax Invoice* is more than what it would have been had the error not been made, the Payment Error* will be taken to have occurred on the date the User* has paid the total amount of the Tax Invoice* in full.

Payment Error means

(a) any underpayment or overpayment by a Party* of any amount in respect of a Tax Invoice*; or

(b) any error in a Tax Invoice* (including the omission of amounts from that Tax Invoice*, the inclusion of incorrect amounts in that Tax Invoice*, calculation errors in the preparation of a Tax invoice* or a Tax Invoice* being prepared on the basis of data which is later established to have been inaccurate).[~~means any underpayment or overpayment by a Party* of any amount in respect of a Tax Invoice~~*.]

1468. Synergy's submission notes that it has discussed these amendments with Western Power and that it understands that the changes are required to deal with circumstances where Western Power has not invoiced a User for several years for a connection point, as typically these connection points have not also had a meter reading for several years. Consequently, when Western Power subsequently discovers such a connection point it is seeking the ability to make these connection points subject to Synergy's access contract and to invoice Synergy for past charges.

1469. Synergy considers Western Power's proposed changes are designed to give effect to such an outcome and do not appear to deal with the genuine circumstances associated with an under or over payment. That is, there is no limitation or sunset provision limiting when Western Power can issue an invoice and demand payment for charges that may or may not have been incurred several years ago. Synergy considers this situation also creates difficulties for a retailer with respect to reconciling such invoices, especially in circumstances when the retailer does not have an accurate list of the connection points on its access contract and, where Synergy is limited in its ability to pass on these amounts under the Code of Conduct and the *Energy Operators Powers Act*.

1470. Synergy submits that such an approach is unreasonable and does not form the basis of a commercially workable access contract. Therefore, Synergy submits that clause 8.6 should remain unchanged from the current access arrangement and the following changes should be made to clause 8.1 and the definition of payment error to clarify the minimum conditions and operation of clause 8.6:

- Clause 8.1 – to contain a provision that makes it clear Western Power must not issue a tax invoice in respect of amounts that would otherwise have been payable under the standard access contract later than 12 months from the date those amounts are payable.
- Payment Error – to be defined as any underpayment or overpayment by a party of any amount in respect of a tax invoice for any amount payable by the User under the standard access contract.

1471. Synergy considers the fundamental problem which results in these types of issues lies in Western Power's inability to provide Users with an accurate list of connection points on the User's access contract.

1472. Synergy requests that Western Power provide an accurate list of connection points in an access contract (as it is fundamental to a retailer's business and hence to a commercially workable access contract).

1473. Synergy notes that it has been seeking an accurate list of the connection points on its access contract and that Western Power continues to have difficulty providing an accurate list. A retailer may only supply electricity to a customer through a connection point on its access contract. Without such a list, it is not possible for a retailer to determine at any given point in time who is taking electricity on its account. Unless a positive obligation to provide an accurate list of connection points on an access contract is imposed, Synergy submits Western Power's proposed changes to the payment error terms under the standard access contract are unworkable as they provide Western Power with the ability to retrospectively, several years later, make Synergy liable for access charges for connection points Western Power may have initially omitted to list on Synergy's access contract.

1474. Similar issues were considered by the Authority at the last access arrangement review and the Authority's final decision for the current access arrangement required the following amendments.

Final Decision Amendment 5

The proposed access arrangement revisions should be amended such that clause 3.7 of the electricity transfer access contract is clear on whether schedule 3 and, where relevant, the metering database, is to be updated only by Western Power, or by either Western Power or the user.

Final Decision Amendment 6

The proposed access arrangement revisions should be amended such that clause 3.7 of the electricity transfer access contract requires Western Power to provide the user with such access to schedule 3 and the metering database as is reasonably required for the user to obtain information or to change relevant information.

Final Decision Amendment 7

The proposed access arrangement revisions should be amended so that the electricity transfer access contract indicates which records of connection point data will have precedence, to the extent of any inconsistency between schedule 3 of the electricity transfer access contract, the metering database and any connection point data contained in the price list.

1475. Amendments were made to 3.7 requiring:

> 3.7(a) Unless the Parties* otherwise agree, Western Power must record the information referred to in Part 1 of Schedule 3, with respect to each Connection Point*, in the Connection Point Database*.
>
> 3.7(b) Subject to clauses 3.7(g) and 3.7(h), Western Power* must update the information contained in a Connection Point Database* following any variation made under this clause 3.
>
> 3.7(c) Upon request by the User* for information referred to in the Connection Point Database*, Western Power* will provide to the User* the most up-to-date version of that information.
>
> 3.7(i) The Parties* must notify each other of any errors discovered in the Connection Point Database* as soon as reasonably practicable after becoming aware of the error.
>
> 3.7(j) Western Power* must amend any error in the Connection Point Database* as soon as reasonably practicable after becoming aware of the error, provided that if Western Power* becomes aware of an error otherwise than by notice from the User* under clause 3.7(i), no amendment shall be made until Western Power* has given notice to the User* of the error.

1476. The Authority considers these amendments provide adequate protection to ensure the connection point database was updated in a timely and accurate manner. The Authority has discussed the matters raised by Synergy in its current submission with Western Power.

1477. Western Power considers that Synergy has misunderstood the intent of the changes made by Western Power to clause 8.6 and does not know to which specific discussions, noted at paragraph 1468 above, Synergy is referring to. Western Power notes that its proposed changes are not intended to give Western Power an entitlement to invoice a User for unread Connection Points and are merely to more accurately define when a Payment Error is taken to have occurred.

1478. Western Power refers to the explanation it provided on page 319 of its proposed revised access arrangement information:

> "The definition of "payment error" requires amendment to cover all of the situations covered by clause 8.6. The present definition is limited only to payment errors where the invoiced amount was correct but not paid in full or overpaid. It does not cover the situation where the tax invoice itself contained the wrong amount because it was calculated using incorrect data."

1479. Western Power also considers that Synergy's claims that clause 8.6 allows Western Power to invoice Synergy for charges dating back several years is incorrect and points to clause 8.6(d) which states that Payment Errors may only be corrected within 18 months of when the error was made.

1480. Western Power also notes that clause 8.6(e) provides that where a Payment Error has occurred as a result of an error in the data used to calculate the Charges "the Party who was underpaid or who made an overpayment (as applicable) is entitled to an adjusting payment only for the Payment Errors that occurred in the Accounting Periods that were within the 12 month period preceding the date that the Payment Errors were notified by one Party to the other". Western Power considers, therefore, that the 12 month limitation period requested by Synergy is already reflected in clause 8.6.

1481. Western Power considers that Synergy's proposed change to the definition of "Payment Error" will only serve to perpetuate the ambiguity in the existing clause as identified by Western Power, in that, the definition will only refer to circumstances where the exact amount is set out in an invoice was not paid and will not cover the scenario where an invoice itself was correct. Western Power also notes that clause 8.2 provides for Users to issue invoices to Western Power so the definition of "Payment Error" needs to cover errors in relation to such invoices.

1482. Overall, Western Power does not consider there is any justification for Synergy's concerns, as the changes proposed by Western Power do not give it an entitlement to make adjustments going back several years and the 12 month period sought by Synergy is already reflected in clause 8.6(e).

1483. The Authority has considered the matters raised by Synergy and the responses provided by Western Power and considers that Western Power's proposed revisions to clause 8.6 and the definition of payment error are reasonable and necessary to more accurately define when a Payment Error is taken to have occurred.

1484. As noted above, the Authority considers the amendments made to the last access arrangement provide adequate assurance that the connection point database is updated in a timely and accurate manner. Synergy has not provided any specific evidence that the current arrangements are not adequate. If Synergy considers Western Power is not complying with its requirements then it needs to bring this to the attention of Western Power and require it to resolve such issues. These are operational matters which do not need to be considered for the purposes of approving the standard access contract.

Payment Duration (clause 8.3)

1485. Clause 8.3 of the standard access contract requires a User to reconcile and pay Western Power's invoices within 10 business days of receiving the invoice. Western Power has not proposed any revisions to clause 8.3 but Synergy has raised some concerns.

1486. Synergy considers a 10 business day period may be reasonable and workable for smaller users and retailers but notes that the invoice it receives from Western Power contains more than 8 million transactions that need to be reviewed, reconciled and paid and that it is not feasible to do this within 10 business days. Synergy submits that payment terms for access charges of 20 business days are reasonable and consistent with industry practice but has provided no examples to support this.

1487. The Authority has discussed Synergy's concerns with Western Power who has since provided the Authority with a summary of payment periods for other Australian gas and electricity legislation and access arrangements. It also notes the provisions of the National Electricity (Retail Support) Amendment Rules 2010, which although yet to come into effect, will regulate the periods within which retailers are required to pay network charges to a distributor. In these rules the due date for payment is defined as being 10 business days from the date of issue specified on a statement of charges.

1488. The Authority has confirmed the information provided by Western Power and agrees that the current payment duration of 10 business days is consistent with industry practice. It therefore considers that the payment terms in clause 8.3 are reasonable and do not require change.

Security for Charges (clause 9)

1489. Western Power has proposed amendments to clause 9, including insertion of a new clauses 9(c) which will require users, on request, to increase security where the existing security given to Western Power at that time is no longer equal to the charges for two months services; and clause 9(e) to manage security in situations where a parent company's circumstances change. Western Power's proposed amendments are set out below.

9. Security for Charges*

(a) Subject to clause 0, if Western Power* determines at any time during the Term* that either or both of the User*'s or the Indemnifier*'s technical or financial resources are such that a Reasonable and Prudent Person* would consider there to be a material risk that the User* will be unable to meet its obligations under this Contract*, then:

(i) Western Power* may require the User* to within 15 Business Days* nominate which of the User* or the Indemnifier* (**"Nominated Person*"**) is to provide ~~the following~~ security; and

(ii) within 15 Business Days* of the User*'s nomination under clause 110(a)(i), ~~then require~~ the Nominated Person*, at the User*'s election, must either ~~to~~:

(A) pay to Western Power* a cash deposit equal to the Charges* for two months' services; or

(B) provide an irrevocable and unconditional bank guarantee or equivalent financial instrument in terms acceptable to Western Power* (acting as a Reasonable and Prudent Person*), guaranteeing or otherwise securing the Charges* for two months' services; or

(C) if Western Power* is satisfied, as a Reasonable and Prudent Person*, that the User*'s parent company's financial and technical resources are such that the User's* parent company would be able to meet the User*'s obligations under this Contract* (including because the User*'s parent company meets at least one of the credit ratings given in clauses 9(b)(i) and9(b)(ii)), procure from the User*'s parent company a guarantee substantially in the form set out in Schedule 8.

(b) If the User* or the Indemnifier* has an unqualified credit rating of at least:

(i) BBB from Standard and Poor's Australia Pty Ltd; or

(ii) Baa from Moody's Investor Service Pty Ltd,

and provides evidence to this effect to Western Power*, then Western Power* is not entitled to determine under clause 110(a) that the User*'s financial resources are such that there would be a material risk that the User* will be unable to meet its obligations under this Contract*.

(c) If any security held by Western Power* under clause (A) or (B) at any time is not equal to the Charges* for two months' services, then the Nominated Person* must, within 15 Business Days* of a written request by Western Power* to the User*:

(i) if the security is a cash deposit under clause (A), provide Western Power* with an additional cash payment to increase the security so that it is equal to the Charges* for two months' services; or

(ii) if the security is a guarantee under clause (B), replace the guarantee with another guarantee (that is in accordance with clause (B) in an amount that is equal to the Charges* for two months' services.

(d) If any security held by Western Power* under clause (A) or (B) is called upon by Western Power* or if that security ceases to be enforceable for any reason (including due to expiry of the security) then within 15 Business Days* the Nominated Person* must provide replacement security to Western Power* complying with the requirements of clause110(a)(ii).

(e) Where a guarantee has been provided to Western Power* by the User*'s parent company but Western Power* ceases to be satisfied, as a Reasonable and Prudent Person*, that the criteria in clause 9(a)(ii)(C) are met then by notice to the User* Western Power* may require the provision of a new form of security complying with the requirements of clause (A) or (B) which security must be provided within 15 Business Days* of service of Western Power*'s notice.

1490. In its submission, Synergy requests amendments to clause 9 to ensure only breaches of material contract obligations are acted upon and proposes clause 9(a) should be amended as follows to clarify the materiality associated with a User not meeting an obligation under the standard access contract:

9(a) Subject to clause 9(b), if Western Power* determines at any time during the Term* that either or both of the User*s or the Indemnifier*s technical or financial resources are such that a Reasonable and Prudent Person* would consider there to be a material risk that the User* will be unable to meet its material obligations under this Contract*…

1491. In its submission, ERM Power accepts Western Power's proposed modifications to security requirements (to cover two months service charges) as long as it is managed to avoid it becoming an administrative burden. ERM Power suggests this could be avoided by a request only being generated when the security amount falls below one month's service charge. ERM notes that a security is supposed to be a nominal amount and is not a guarantee to recover lost revenue.

1492. ERM Power also raises concerns with the proposed amendments which require replacement security to be provided if the security is called on or if that security ceases to be enforceable for any reason, including as a result of the expiry of the security. ERM Power states that it believes a security is generally called upon in circumstances of hardship and an additional burden of replacing the security would not be welcome and may not be successful. ERM Power considers that if the security ceases to be enforceable then a remedy ought to be found and it is unlikely this will just be providing a replacement security.

1493. Landfill Gas and Power considers that Western Power should also pay interest on cash security deposits, in common with the practice of the IMO.

1494. The Authority considers it is unnecessary and confusing to insert the word "material" to clause 9(a) as suggested by Synergy. Among other things, a primary purpose of clause 9(a) is to specify the 'threshold test' to be applied by Western Power in determining whether or not Western Power will require security from a User (or indemnifier). It is not, and does not require, an analysis of which "obligations" Western Power needs to consider in making such a determination.

1495. The Authority notes ERM Power's concern that the proposed modifications should be managed so as to minimise administrative costs and agrees that it is reasonable that requests should only be generated by Western Power in circumstances where the security falls below a specific threshold. The Authority is also concerned that the operation of the existing clause 9 is unclear in a couple of other material respects. In particular:

- it is not clear from clause 9(a) or clause 9(c) which "two months' services" the charges are referrable to. A reference point is important where the charges are not fixed. Without a reference point, the applicable "two months" period in both clauses is ambiguous; and
- clause 9 does not specify the circumstances in which Western Power can draw or call on the security and whether the security is refundable, or returnable (as the case may be), to the relevant user (or indemnifier) when the contract is at an end.

1496. In response to the Authority's concerns about the drafting of the existing clause 9, Western Power noted that the current clause is based on the model ETAC which does not expressly address these matters.

1497. Western Power submits that, in the absence of an express statement as to when it can draw on security, it may draw on security to recover any amount due to it under the contract but unpaid. Western Power notes this is consistent with the approved form of parent company guarantee in Schedule 8 of the ETAC. It is also consistent with the terms of clause 9(a), which refers to the User meeting all of its obligations under the ETAC, not limited to specific obligations.

1498. However, Western Power proposes to address the issues raised by the Authority by adding paragraphs (f) to (h) below to clause 9:

> "(f) Upon the expiry or termination of this Contract and receipt by Western Power of all amounts due by the User to it under this Contract Western Power will return to the User any security provided under this clause 9 which is still held by Western Power.
>
> (g) Western Power may call upon a cash deposit or bank guarantee (or equivalent financial instrument) provided to it under this clause 9 if an amount due by the User to Western Power under this Contract is not paid by the due date for payment of that amount or, where this Contract does not specify a due date for payment, is not paid within 10 Business Days of Western Power issuing a notice to the User requiring payment of the amount.
>
> (h) In this clause 9, a reference to the Charges for two months services means Western Power's reasonable estimate of the Charges which will be incurred by the Customer for the Services provided under this Contract in the next two calendar month period from the end of the next Accounting Period (that is, from the end of the Accounting Period which expires after

the Accounting Period in which the User is notified of the current level of security it is required to provide)."

1499. The Authority is of the view that Western Power's proposed additional clauses 9(f), (g) and (h) are reasonable and provide clarity to the operation of clause 9, reducing the risk of disputes about the parties' rights under this clause. Subject to consideration of submissions from users and other interested parties, the Authority proposes to require these clauses to be included in the ETAC.

Required Amendment 66

An amendment is required to the electricity transfer access contract to reflect the amendments set out in paragraph 1498 above.

1500. The Authority notes ERM Power's point that it may not be possible to provide replacement security in circumstances of hardship, but that it is not relevant to the determination of a standard electricity transfer access contract, and further, is not a valid reason for a user to be in breach of the obligation to provide such security under clause 9(a).

1501. The Authority agrees that it would be reasonable for Western Power to pay interest on cash security deposits and that this should be specified in the electricity transfer access contract.

Required Amendment 67

An amendment is required to the electricity transfer access contract to include a clause requiring Western Power to pay interest on cash security deposits provided by users.

APPLICATIONS AND QUEUING POLICY

Access Code Requirements

1502. Section 5.1(g) of the Access Code requires that an access arrangement include an applications and queuing policy. Sections 5.7 to 5.11 of the Access Code set out the requirements for anapplications and queuing policy.

5.7 An applications and queuing policy must:

(a) to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants; and

(b) be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate; and

(c) set out a reasonable timeline for the commencement, progressing and finalisation of access contract negotiations between the service provider and an applicant, and oblige the service provider and applicants to use reasonable endeavours to adhere to the timeline; and

(d) oblige the service provider, subject to any reasonable confidentiality requirements in respect of competing applications, to provide to an applicant all commercial and technical information reasonably requested by the applicant to enable the applicant to apply for, and engage in effective negotiation with the service provider regarding, the terms for an access contract for a covered service including:

(i) information in respect of the availability of covered services on the covered network; and

(ii) if there is any required work:

A. operational and technical details of the required work; and

B. commercial information regarding the likely cost of the required work;

and

(e) set out the procedure for determining the priority that an applicant has, as against another applicant, to obtain access to covered services, where the applicants' access applications are competing applications; and

(f) to the extent that contestable consumers are connected at exit points on the covered network, contain provisions dealing with the transfer of capacity associated with a contestable consumer from the user currently supplying the contestable consumer ("outgoing user") to another user or an applicant ("incoming user") which, to the extent that it is applicable, are consistent with and facilitate the operation of any customer transfer code; and

(g) establish arrangements to enable a user who is:

(i) a ‘supplier of last resort’ as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and

(ii) a ‘default supplier’ under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations; and

(h) facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the ‘market rules’ as defined in section 121(1) of the Act; and

(i) if applicable, contain provisions setting out how access applications (or other requests for access to the covered network) lodged before the start of the relevant access arrangement period are to be dealt with.

5.8 The paragraphs of section 5.7 do not limit each other.

5.9 Under section 5.7(e), the applications and queuing policy may:

(a) provide that if there are competing applications, then priority between the access applications is to be determined by reference to the time at which the access applications were lodged with the service provider, but if so the applications and queuing policy must:

(i) provide for departures from that principle where necessary to achieve the Code objective; and

(ii) contain provisions entitling an applicant, subject to compliance with any reasonable conditions, to:

A. current information regarding its position in the queue; and

B. information in reasonable detail regarding the aggregated capacity requirements sought in competing applications ahead of its access application in the queue; and

C. information in reasonable detail regarding the likely time at which the access application will be satisfied;

and

(b) oblige the service provider, if it is of the opinion that an access application relates to a particular project or development:

(i) which is the subject of an invitation to tender; and

(ii) in respect of which other access applications have been lodged with the service provider,

(“project applications”) to, treat the project applications, for the purposes of determining their priority, as if each of them had been lodged on the date that the service provider becomes aware that the invitation to tender was announced.

5.9A If:

(a) an access application (the “first application”) seeks modifications to a contract for services; and

(b) the modifications, if implemented, would not materially impede the service provider's ability to provide a covered service sought in one or more other access applications (each an "other application") compared with what the position would be if the modifications were not implemented,

then the first application is not, by reason only of seeking the modifications, a competing application with the other applications.

5.10 An applications and queuing policy may:

(a) be based in whole or in part upon the model applications and queuing policy, in which case, to the extent that it is based on the model applications and queuing policy, any matter which in the model applications and queuing policy is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model applications and queuing policy; and

(ii) sections 5.7 to 5.9;

(iii) the Code objective; and

(b) be formulated without any reference to the model applications and queuing policy and is not required to reproduce, in whole or in part, the model applications and queuing policy.

5.11 The Authority:

(a) must determine that an applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective to the extent that it reproduces without material omission or variation the model applications and queuing policy; and

(b) otherwise must have regard to the model applications and queuing policy in determining whether the applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective.

Current Access Arrangement

1503. The current access arrangement includes, at Appendix 1, an applications and queuing policy describing the process that an applicant (i.e. a person who seeks to obtain or modify a covered service) must undertake with Western Power to form, or to modify, an access contract.

1504. The current applications and queuing policy deals with the following matters:

- procedural requirements for an access application and access offer (Part A);
- procedural requirements specific to an electricity transfer application (Part B); and
- procedural requirements for a connection application (Part C).

1505. The procedural requirements for a connection application include "queuing rules" (clause 24). The queuing rules apply where Western Power receives two or more competing connection application: that is, applications for which the provision of the service sought in one connection applications may impede Western Power's ability to provide the covered services that are sought in other connection applications.

1506. Under the current applications and queuing policy, Western Power may:

- establish more than one queue, such as different queues for different parts of the network (clause 24.4);
- determine that an application will by-pass a queue (clauses 24.5 to 24.9);
- assign the same priority in a queue to applications that are competing under a tender process such that only one application will ultimately proceed with an access contract (clause 24.10);
- determine that an application is a "dormant application" and make a determination on whether the dormant application should be taken to have been withdrawn (clause 24.14).

Proposed Revisions

1507. Following are some of the reasons Western Power considers that revisions to the applications and queuing policy are required.[383]

- Western Power faces significant challenges in undertaking applicant studies in accordance with the current policy and this is leading to delays and costs that are ultimately worn by applicants.
- The current policy requires Western Power to exercise discretion over an applicant's readiness to progress and this introduces risks to the applicant and Western Power (with discretion in determination of applications as dormant applications and discretion on determining that an application may by-pass of the queue).
- The current process distorts the basis on which new generation projects can compete in the wholesale electricity market, with potential adverse impacts on the wholesale electricity market and on the commissioning of renewable energy projects.

1508. Western Power's proposed revised applications and queuing policy is contained in Appendix B of the proposed revised access arrangement. Western Power describes the broad nature of revisions to the applications and queuing policy as follows:[384]

- Customer driven nature

  [A]pplicants determine how they progress through the process through explicit decision stages where they lodge applications, initiate planning studies, accept/decline preliminary offers and decide whether to accept the final access offers that we make to them. Beyond these decisions the process is largely mechanical, which removes our need to exercise discretion by classifying customer applications as dormant or initiating bypass of applications to promote other applicants in the queue.

- Less need for a queue

[383] Revised access arrangement information, p. 324.

[384] Revised access arrangement information, pp. 325,326.

> At present there is a single queue where applicants remain in the order they arrive, regardless of their readiness to proceed to connection. Instead ... the applicants that are commercially ready with viable projects determine their own willingness to proceed, or alternatively withdraw from the process as they approach decision stages and the payment of associated fees.

1509. Western Power describes the key aspects of the revisions as follows:[385]

> The addition of a formal enquiry stage – included to facilitate the exchange of information and to assist applicants to better indicate their requirements.
>
> The creation of 'competing applications groups' (CAGs), where applicants are grouped behind common network constraints to assess and tailor joint network solutions to provide access to all applicants within the CAG – rather than the current process which provides one-off, single applicant solutions that leads to the less efficient and more costly augmentation of our network over time.
>
> Limited use of queuing – different pathways exist for customers with different issues. There is no longer a single queue and applicants will only queue if a particular CAG is over-subscribed.

1510. Further elements of the proposed revisions are listed by Western Power as follows:[386]

> - The 'enquiry response letter' will provide the applicant with information on capacity, known network constraints and the existence of competing applications.
> - Applicants can select their own engineering firm to undertake the necessary studies required by the applications and queuing policy process.
> - Where study costs exceed our pre-estimate, applicants will be advised before additional costs are incurred and will have the opportunity to choose their desired course of action.
> - Western Power will inform all applicants in a CAG when an applicant-specific solution has been prepared for one of the applicants within the CAG, to provide all applicants with an opportunity to object.
> - Applicants will be advised in writing seven business days prior to a 'deemed withdrawal' as a result of their unpaid fees or charges.
> - Applicants will be able to amend their application after the applicant has received a preliminary access offer, where we agree that the amendment sought is not material.
> - When processes are commenced to develop joint network solutions for a CAG, those processes will not be interrupted by new applications except in circumstances where existing applications have withdrawn and new applications can replace the existing applications without delay to the process.
> - Timelines for various procedural steps have been inserted including:
>   - the time to process enquiries (40 business days)

[385] Revised access arrangement information, p. 326.

[386] Revised access arrangement information, p. 327.

- – the time to resolving objections to applicant-specific solutions (40 business days)
- – Indicative timeframes for provision of preliminary and final access offers to applicants in a CAG (30 business days).

1511. Western Power considers that the proposed revisions to the applications and queuing policy are likely to lead to a more economically efficient connection of projects for the following reasons:[387]

- There is a more straightforward process for applications not subject to constraints.

  > Applications that are not subject to constraints from the CAG process have a more direct pathway to connection. For example, 'transfer only' or 'connection only' applications can proceed immediately to connection without being held up by applicants that sit above them in the queue that face delay due to network constraints. This creates a more efficient process for applicants that are not competing for limited capacity on the shared network.

- Work to augment the network to provide customer access occurs according to constraint/issue type rather than being driven by individual customers.

  > Our revisions allocate customers with similar constraints together into CAGs so that our work can focus on resolving the common network constraint, rather than single augmentations for each individual customer. This means work to successfully resolve the constraint means many customers can move forward and if any customer wishes not to proceed they can leave the group without disrupting the others.
  >
  > Under our current approach, customers are placed in a single queue and work to connect them occurs on an individual customer basis. This can result in inefficiencies as any changes to a customer's application (for example a customer leaving the queue or not being ready to proceed) impact those in the queue behind them. This requires costly and continual study reworks to re-evaluate the queue each time a project's status changes, or if a 'queue bypass' is required when an applicant is unduly holding up others in the queue.

- Long-term strategic network augmentations deliver more efficient network outcomes.

  > Grouping applicants within CAGs also provides greater scope to deliver long-term strategic network augmentations. The use of CAGs provides visibility to identify the types of constraints and number of applicants impacted and, as a result, allows planning decisions to be made that will see the greatest number of customers efficiently connected at the same time. Network augmentation in this manner is likely to bring about more efficient, lower cost solutions in comparison to a process which makes continuous and numerous one-off augmentations to connect individual applicants.

Submissions

1512. Submissions on the proposed revised applications and queuing policy are addressed below under "Considerations of the Authority".

[387] Revised access arrangement information, pp. 326, 327.

Considerations of the Authority

1513. The Authority is required to assess the proposed revisions to the applications and queuing policy against the requirements of sections 5.7 to 5.11 of the Access Code.

1514. The Authority received thirteen submissions which referred to Western Power's proposed revisions to the applications and queuing policy. Except for submissions from Synergy and Pacific Hydro, submissions were broadly in support of the proposed revisions to the applications and queuing policy.

1515. The concerns raised by Synergy primarily relate to its view that the proposed applications and queuing policy provides Western Power with absolute discretion to constrain connection and covered services and that it would be more appropriate to deal with network constraints through economic initiatives and price signals. The Authority does not agree that the proposed applications and queuing policy provides Western Power with absolute discretion to constrain connection and covered services. Whilst economic initiatives and price signals may form part of a better solution to network constraints, the Access Code requires Western Power to include an applications and queuing policy in its access arrangement and the Authority is obliged to assess that policy against the requirements of the Access Code.

1516. The matters raised by Pacific Hydro relating to the operation of the policy are addressed by the Authority below.

1517. In assessing whether the proposed revised applications and queuing policy meets the requirements of the Access Code, the Authority has considered the following:

- the interests of the service provider, users and applicants;
- sufficient detail on how the applications and queuing policy will operate;
- timelines;
- information provision by Western Power;
- priority;
- Customer Transfer Code;
- suppliers of last resort and default suppliers;
- facilitation of Part 9 of the Act;
- priority of access applications lodged before the start of the third access arrangement period; and
- other matters raised in submissions.

Interests of the service provider, users and applicants

1518. Section 5.7(a) of the Access Code requires that an applications and queuing policy must, to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants.

1519. On 23 December 2010 the Authority received a proposal from Western Power to vary its Application and Queuing Policy (**AQP**). After a public consultation process and assessment of key issues raised, and noting the short period of time before the AA3 review was to commence, the Authority determined not to vary the applications and queuing policy mid-term and referred it for assessment as part of thethird access arrangement review process as there were a number of issues raised in submissions which it considered needed to be addressed.

1520. Western Power states that its proposed applications and queuing policy revisions for AA3 build on the mid-term revisions that were proposed during the current access arrangement period and take into account the issues stakeholders raised through the Authority's consultation process. Western Power has provided a summary of how it has responded to those issues.[388]

1521. The Authority acknowledges the effort Western Power has made to take account of the interests of users and applicants. The Authority notes that there has been considerable work, review and discussion undertaken to date by many parties over a long period of time, as outlined below:

- July 2009 – The Authority's "2009 Annual WEM Report" raised concerns in relation to Western Power's existing AQP first-come first-served queuing rules and their interaction with the WEM and the reserve capacity mechanism, suggesting it did not serve to promote efficient investment in the electricity network.
- August 2009 – Western Power released a Discussion Paper on application and queuing policy issues with initial proposals seeking views from interested parties and held a public forum.
- September 2009 – an AEMC review of Western Australia's energy market framework commented on and suggested changes were required to Western Power's connections application process.
- December 2009 – Western Power published its Consultation Proposal, providing background and rationale for proposed AQP changes (follow-up submissions were received).
- November 2010 – Western Power held an applications and queuing policy public forum on its proposed changes (40 attendees).
- December 2010 – Western Power submitted proposed mid-term applications and queuing policy revisions to the Authority (pursuant to Access Code 4.41).
- January 2011 – The Authority sought public submissions on Western Power's proposed mid-term applications and queuing policy revisions (6 received).
- April 2011 – The Authority determined not to vary the applications and queuing policy mid-term but referred it for assessment in the upcoming AA3 review process as there were a number of issues raised in submissions which needed to be addressed.
- September 2011 – Western Power submitted its AA3 proposed revisions, including Western Power's response to the queries raised in the submissions received during the Authority's public submission process.

1522. In its submission the Office of Energy raised a concern that the detailed mechanics of the proposed AQP may not have been fully developed or may not have been adequately communicated to and understood by stakeholders. The Office of

[388] Proposed revised access arrangement information Appendix J: Response to submissions to the proposed mid-term revisions to the applications and queuing policy.

Energy therefore proposed that Western Power should provide a further series of workshops to interested stakeholders.

1523. In its submission Pacific Hydro notes the time that has passed since Western Power's original proposal in December 2009 and considers there is a need for specific consultation in relation to the applications and queuing policy as it considers the scope of the access arrangement limits the ability for the dedication of specific time and resources on this topic.

1524. Western Power held a stakeholder workshop on 3 February 2012 to provide further explanation and opportunity for comment in relation to the proposed applications and queuing policy. The forum was attended by a broad cross-section of interested parties. Many issues, queries, questions and criticisms were raised and discussed in what appeared to be a very beneficial workshop for all attendees.

1525. The Authority considers that Western Power has undertaken an adequate consultation process with interested parties. Submissions received by the Authority from interested parties who have direct practical experience of the current applications and queuing policy, indicates significant support for the proposed revisions. Apart from a number of specific concerns, which the Authority has addressed below, having regard to the level of consultation and the submissions received by the Authority in support of the proposed revisions,, the Authority is satisfied the proposed revisions comply with the requirements of section 5.7(a) of the Access Code.

1526. Specific concerns raised in submissions have been addressed by the Authority below.

Formal Enquiry Process

1527. In its submission Perth Energy questioned whether the proposed formal enquiry process would materially reduce time and resources for an access application compared to an informal enquiry stage.

1528. Whilst the actions under a formal or informal enquiry may be similar, the Authority is of the view that a description of the full process of enquiry in the policy improves the process by clarifying actions and expectations.

Deemed Withdrawal of Applications

1529. In its submission Landfill Gas and Power considers the provisions for the deemed withdrawal of an application should be conditional on an express requirement in the policy for Western Power to act reasonably.

1530. The Authority agrees that there should be an express requirement for Western Power to act reasonably in deeming that an application has been withdrawn.

Required Amendment 68

The applications and queuing policy must be amended to include an express requirement for Western Power to act reasonably in deeming that an application has been withdrawn.

Technical Disputes

1531. In its submission ERM Power notes that technical disputes should be treated as an access dispute to be referred for arbitration under clause 20.4.

1532. Although clause 20.4 of the proposed applications and queuing policy provides that a dispute on costs for a connection application may be referred to the arbitrator as an access dispute, it does not limit the matters that may be the subject of an access dispute. An access dispute is defined in section 1.3 of the Access Code and may include a dispute in relation to any of the terms, including technical requirements, for access. As such, the Authority does not consider it necessary for clause 20.4 to expressly state that technical disputes are to be referred to arbitration. However, to avoid doubt, the Authority considers clause 20.4 should be amended to include a statement to that effect.

Required Amendment 69

Clause 20.4 of the applications and queuing policy must be amended to include the following:

"Nothing in this clause limits the matters that may be the subject of an access dispute.".

Fees for Enquiry Stage

1533. Section 18.4 of the proposed applications and queuing policy provides for Western Power to charge a non-refundable fixed fee when an applicant lodges an enquiry.

1534. Wind Prospect's submission considers the formal enquiry stage should be a free service and notes that this is the case in the NEM. Wind Prospect considers that if a fee is to be charged, it should not be non-refundable and the level of fee should be explicitly stated within the applications and queuing policy.

1535. The Authority considers it is reasonable for Western Power to charge a non refundable fee having regard to the administrative costs associated with the service and so as to discourage spurious applications. Under clause 17A.1 a party is able to have informal non binding discussions with Western Power which the Authority considers should give a prospective applicant an opportunity to evaluate whether it wishes to proceed to lodge a formal application.

1536. The Authority notes that the proposed Price List for 2012/13, which is included as Appendix F.1 to the proposed revised access arrangement, includes a list of lodgement fees applicable to the applications and queuing policy. The Authority considers it would be clearer to applicants if the applications and queuing policy specifically referred to the Price List where relevant.

Required Amendment 70

The applications and queuing policy must include specific reference to the Price List in relation to the relevant fees.

Removal of Bypass Provisions

1537. In its submission Pacific Hydro raises concerns in relation to the removal of the bypass provisions in the proposed revised applications and queuing policy. Pacific Hydro considers the existing bypass arrangements to be adequate for generation and that Western Power has not provided details on why the current bypass process is not efficient.

1538. The Authority notes that Western Power considers the implementation of the bypass mechanism has proven to be problematic in practice and, even when implemented effectively, it does not make provision for joint connection solutions. Western Power considers that retaining applicant-specific solutions as an option produces the same result as an efficiently implemented bypass mechanism.[389]

1539. The Authority considers Western Power's approach to be reasonable, having regard to the difficulties associated with the existing applications and queuing policy.

Applicant Specific Solutions

1540. Perth Energy's submission considers that Western Power's proposal that members of a competing applications group can object if one member of the group is offered an applicant-specific solution, may be used in a vexatious manner to hinder the progress of a competing application or to enforce participation in a joint solution that may not be in the best interest of individual applicants. Perth Energy considers the process for competing applications groups needs to allow for individual applicants to opt out of a competing applications group and to pursue stand-alone access applications where the participation in a competing applications group may hinder the progress of an access application.

1541. The Authority notes that pursuant to clause 20.3(a) an applicant may request Western Power to perform a study of the nature and costs of an applicant-specific solution to satisfy the connection application.

1542. However, pursuant to clause 20.3(b), once Western Power has completed the study, it must provide existing users and any competing applicants within the same competing applications group as the applicant, with the opportunity to object to

[389] Western Power proposed revised access arrangement information Appendix X, p. 17.

providing the applicant-specific solution to the applicant. Existing users and competing applicants may object on the grounds that (clause 20.3(c)):

- the applicant-specific solution would impede Western Power's ability to provide covered services to the existing user; or
- the applicant specific solution would impede Western Power's ability to provide the covered services that are sought in a competing application compared with what the position would be if the applicant-specific solution were not implemented.

1543. Clause 20.3(d) requires Western Power to evaluate any such objections within 40 business days of such an objection being lodged. If Western Power agrees that the applicant-specific solution would impede its ability to provide covered services to an existing user or to provide the covered services that are sought in the other connection application to a competing applicant, then it must either decline to offer an applicant-specific solution to the applicant or modify the applicant-specific solution to remove the impediment.

1544. The Authority notes that clause 24.2 gives Western Power the discretion to determine that an application be treated as part of a competing applications group. However, under clause 24.3, an applicant may withdraw its application if it does not agree to have its application considered within a competing applications group. Further, under clause 24.5(ii), an application will be deemed to be withdrawn if the applicant and Western Power are unable to agree on the terms of a preliminary access offer within the timeframe specified in that clause.

1545. Sections 2.10 and 2.11 of the Access Code, require Western Power to undertake required works to provide a connection subject to the user paying any necessary contribution to the costs of those required works. The Authority considers that the proposed applications and queuing policy is not consistent with the rights of an applicant under sections 2.10 and 2.11 of the Access Code as it does not provide for an applicant to have an application treated independently of any other application, even in circumstances where the applicant will fully fund the solution. To ensure applicants rights under sections 2.10 and 2.11 of the Access Code are preserved the Authority requires that:

- clauses 24.2 and 24.3 be amended to provide for an applicant to opt out of the competing applications group process before that process commences and for the application to be treated as an application for an applicant-specific solution; and
- clause 24.5 of the applications and queuing policy be amended so that if an applicant does not reach agreement with Western Power on a preliminary access offer as part of the competing applications group process, the application is not deemed to be withdrawn but is to be treated as an application for an applicant-specific solution.

Required Amendment 71

To ensure the applications and queuing policy is consistent with sections 2.10 and 2.11 of the Access Code, the applications and queuing policy must provide for an applicant to have an application treated independently of any other application. To give effect to this requirement:

- clauses 24.2 and 24.3 must be amended to provide for an applicant to opt out of the competing applications group process before that process commences and for the application to be treated as an application for an applicant-specific solution; and
- clause 24.5 be amended so that if an applicant does not reach agreement with Western Power on a preliminary access offer as part of the competing applications group process, the application is not deemed to be withdrawn but is to be treated as an application for an applicant-specific solution.

Progress of Applications

1546. In its submission, Alinta submission considers applicants should be required to meet specific criteria, such as environmental approval, fuel supply agreements or power purchase agreements, before being able to progress from the enquiry stage to the connection application stage.

1547. The Authority notes Alinta's concern that parties may submit applications prior to projects being sufficiently developed for the application to proceed in a timely manner, thereby possibly delaying the processing of applications of other parties. However, the Authority considers that to accommodate applicants needs, in some cases these processes will need to progress in parallel. The Authority considers the proposed applications and queuing policy, which requires that applicants provide a complete application form, including all of the relevant information set out in clause 3, provides a reasonable balance of accommodating specific applicant's needs with ensuring other applicants are not unnecessarily disadvantaged.

Sufficient detail on how the applications and queuing policy will operate

1548. Section 5.7(b) of the Access Code requires that an applications and queuing policy must be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate.

1549. In some submissions[390] received by the Authority, parties have expressed concern over a lack of detail in the operation of the 'competing applications group' mechanism. These concerns include:

[390] Griffin Power, Alinta.

- how competing applications in a “competing applications group” will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

1550. Having regard to the submissions received, the Authority considers the mechanisms and processes with respect to the competing applications group could be more clearly defined, whilst ensuring that those mechanism do not become unworkable. The Authority acknowledges that there needs to be a balance between a prescriptive process and flexibility for Western Power to identify an efficient network investment that meets the needs, collectively, of applicants.

Required Amendment 72

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- how competing applications in a “competing applications group” will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and
- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

Timelines

1551. Section 5.7(c) of the Access Code requires that an applications and queuing policy must set out a reasonable timeline for the commencement, progressing and finalisation of access contract negotiations between the service provider and an applicant, and oblige the service provider and applicants to use reasonable endeavours to adhere to the timeline.

1552. The Authority has received submissions raising concerns with respect to the timelines under the applications and queuing policy. The Authority considers these issues below.

Penalties for Non Compliance

1553. Perth Energy supports the timelines specified in the proposed applications and queuing policy, but considers Western Power should face penalties if it does not comply with the relevant prescribed timelines.

1554. The Authority observes that compliance with the applications and queuing policy (including timing requirements) is a matter to be enforced through the access disputes regime under Chapter 10 of the Access Code and, in particular, section 10.29(a). Accordingly, the Authority does not consider any amendments in this respect are required to the applications and queuing policy.

Time Limits for Applicant Specific Solutions

1555. In its submission, ERM Power considers that time limits should be included in section 20.3 which deals with applicant-specific solutions.

1556. As discussed in paragraphs 1540 to 1545 above, the Authority considers the applications and queuing policy should allow an applicant to opt out of the competing applications group process, in which case full timelines for the applications process should apply to an applicant-specific solution.

Required Amendment 73

Ttimelines for applicant-specific solutions must be stated in line with the timelines for competing application groups.

Enforcement of Timelines

1557. Moonies Hill submitted that timelines should be worded so as to create a firm obligation for Western Power (e.g. section 18.2(a)(b) – “endeavour” should be changed to “must”).

1558. The Authority considers it reasonable that such a requirement should be placed on Western Power if the activity to which the timeline relates is one that is predictable for which a pre-determined timeline can reasonably be established. However, for activities which are difficult to predict, the Authority considers it reasonable that it be on a best endeavours basis. The Authority considers Western Power should review the proposed applications and queuing policy to ensure the timeline requirements are appropriate and would welcome further views from interested parties.

Timeframe for Responding to Enquiries

1559. Wind Prospect considers Western Power should be required to respond to enquiries within 20 business days rather than the 40 business days proposed by Western Power.

1560. The Authority notes that Western Power has proposed the response letter will set out:

- a description of the information required for a complete application, and the results of any assessment that it may have carried out to indicate the extent of any spare capacity available to provide covered services;
- the existence of any competing applications; and
- any constraints known to Western Power on the ability of the network to provide the capacity proposed as contracted capacity in the connection application by the applicant. This should be considered in the context of the potential actions required by Western Power in responding to the enquiry and whether 20 or 40 business days would be a better estimate of the time required for this activity.

1561. The Authority considers that most of this information should already be available to Western Power as part of its network planning and on that basis it would be reasonable to expect a response to be prepared within 20 business days. The Authority considers this would facilitate a more efficient process as an applicant would be able to more quickly determine whether it wished to proceed with an application. The Authority acknowledges there may be some cases with greater complexity which require a longer time frame and, in such cases, Western Power should be required to provide an expected response time to the applicant within 20 business days of lodgement of the enquiry.

Required Amendment 74

Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.

Information provision by Western Power

1562. Section 5.7(d) of the Access Code requires that an applications and queuing policy must oblige the service provider, subject to any reasonable confidentiality requirements in respect of competing applications, to provide to an applicant all commercial and technical information reasonably requested by the applicant to enable the applicant to apply for, and engage in effective negotiation with the service provider regarding, the terms for an access contract for a covered service including:

- information in respect of the availability of covered services on the covered network; and
- if there is any required work:
  - operational and technical details of the required work; and
  - commercial information regarding the likely cost of the required work (5.7(d)).

1563. Some submissions received by the Authority raise concerns with respect to the level of information provided and that the confidentiality requirements of Western Power creates difficulties for applicants using external consultants. These Authority considers these matters below.

Level of Information Provided

1564. Submissions from Perth Energy and Moonies Hill consider that Western Power should be required to provide high level detail regarding network access and capacity constraints and considerations, existing applications and network performance issues that would be relevant to the deliberations of any prospective applicants.

1565. The Authority notes that clause 17A.1 which relates to pre-enquiry discussions only states that Western Power will provide reasonable assistance and does not provide any detail of what that assistance might include.

1566. Under clause 18.1, the enquiry stage is only open to applicants who expect in good faith to proceed to a connection application. Clause 18.2A requires Western Power to issue an enquiry response letter to an applicant at the conclusion of the enquiry stage setting out:

- a description of the information required for a complete application, and the results of any assessment that it may have carried out to indicate the extent of any spare capacity available to provide covered services;
- the existence of any competing applications; and
- any constraints known to Western Power on the ability of the network to provide the capacity proposed as contracted capacity in the connection application by the applicant.

1567. The Authority notes that section 5.7(d) of the Access Code requires a service provider to provide certain information to enable an applicant to apply for an access contract. Under the proposed revisions to the applications and queuing policy, Western Power is obliged to only provide such information to parties who expect in good faith to proceed to a connection application. The Authority notes the concerns raised by interested parties that prospective applicants should have access to such information. The Authority agrees that such information is needed to enable potential applicants to decide if they wish to pursue an application. The Authority considers the pre-enquiry stage should include a specific requirement for Western Power to provide potential applicants with all commercial and technical information reasonably requested and subject to any reasonable confidentiality requirements.

Required Amendment 75

The applications and queuing policy must be amended to include an obligation for Western Power to provide potential applicants with all commercial and technical information reasonably requested, and subject to any reasonable confidentiality requirements, at the pre-enquiry stage.

Confidentiality Requirements for Consultants

1568. Pacific Hydro considers that the confidentiality requirements of Western Power makes the use of external consultants difficult.

1569. The Authority notes Western Power has included provisions in the proposed revised applications and queuing policy for the use of external consultants and will provide “all reasonable information” for such purpose (clause 20.5). The Authority considers this requirement addresses the concerns raised by Pacific Hydro Australia. The Authority considers that the confidentiality requirements (i.e. that the consulting engineering firm enter into a confidentiality agreement with Western Power) are reasonable as the information provided may include information that is specific to particular network users and is commercially sensitive. The Authority notes there is nothing in clause 20.5 that indicates that information provision would be restricted for reasons of confidentiality.

Priority

1570. Section 5.7(e) of the Access Code requires that an applications and queuing policy must set out the procedure for determining the priority that an applicant has, as against another applicant, to obtain access to covered services, where the applicants’ access applications are competing applications.

1571. The current applications and queuing policy sets out rules in relation to queuing in clause 24. In the proposed revised applications and queuing policy, clause 24 has been amended to set out the procedures for where there are competing applications and a new clause 24A, has been included dealing with priority dates of applications competing under a tender process.

1572. No submissions made to the Authority raised concerns in relation to the procedure for determining priority of competing applications. The Authority has reviewed the proposed clauses and, having regard to no concerns have been raised in submissions, considers the proposed revised applications and queuing policy adequately sets out the procedure for determining priority of applications.

Customer Transfer Code

1573. Section 5.7(f) of the Access Code requires that an applications and queuing policy must, to the extent that contestable consumers are connected at exit points on the covered network, contain provisions dealing with the transfer of capacity associated with a contestable consumer from the user currently supplying the contestable consumer (“outgoing user”) to another user or an applicant (“incoming user”) which, to the extent that it is applicable, are consistent with and facilitate the operation of any customer transfer code.

1574. Transfers of capacity across exit points are dealt with under clauses 8, 9 and 10 of the proposed applications and queuing policy. No material changes are proposed to these clauses and no concerns have been raised in any submissions made to the Authority on provisions for the transfer of capacity. The Authority considers that clauses 8, 9 and 10 are consistent with the requirements of section 5.7(f) of the Access Code.

Suppliers of last resort and default suppliers

1575. Section 5.7(g) of the Access Code requires that an applications and queuing policy must establish arrangements to enable a user who is:

> (i) a 'supplier of last resort' as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and
>
> (ii) a 'default supplier' under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations (5.7(g)).

1576. Under the current applications and queuing policy, provision is made for an application to bypass the queue when necessary to meet the requirements of section 5.7(g) of the Access Code (clause 24.5 of the current applications and queuing policy). No equivalent provision is contained in the proposed revisions to the applications and queuing policy and there is no specific reference in the proposed policy to the circumstances set out in section 5.7(g) of the Access Code.

1577. A supplier of last resort is a retailer of electricity that assumes an obligation to make a retail supply of energy to a customer where the incumbent retailer of energy to that customer ceases to have a retail licence. A default supplier is a retailer of electricity that is deemed to have a supply contract with a customer that is taking energy at a connection point but does not have a contract with a retailer.

1578. The Authority notes that a supplier of last resort or a default supplier would only assume an obligation to supply energy where there is an existing connection point and existing supply of energy. Clause 9.1 deals with customer transfer requests. However, clause 9.1 was not specifically drafted to deal with a supplier of last resort assuming its obligations, and contains provisions that the Authority considers would constrain the ability of a supplier of last resort or a default supplier to meet their obligations.

1579. The Authority does not consider the proposed applications and queuing policy makes sufficient provision for a party to enter into an electricity transfer access contract to meet obligations as referred to in section 5.7(g) of the Access Code. The Authority considers an amendment is required to include such provisions.

Required Amendment 76

The applications and queuing policy must be amended to include arrangements to enable :

- a ‘supplier of last resort’ as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and
- a ‘default supplier’ under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations (5.7(g)).

Facilitation of Part 9 of the Act

1580. Section 5.7(h) of the Access Code requires that an applications and queuing policy must facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the ‘market rules’ as defined in section 121(1) of the Act.

1581. Part 9 of the Act deals with establishing a wholesale electricity market and provides the head of power for the Market Rules. Section 5.7(h) requires, in practical terms, that the applications and queuing policy facilitate the operation of the wholesale electricity market.

1582. The current access arrangement is based on a first-come first-served queuing principle. As the queuing rules were materially the same as the queuing rules under clauses A2.45 and A2.50 of the model applications and queuing policy under the Access Code, section 5.11 of the Access Code required the Authority to determine that the first-come first-served queuing principle of the applications and queuing policy is consistent with the Code objective.

1583. Notwithstanding that the Authority was required to determine that the first-come first-served queuing rules met the requirements of the Access Code, the Authority considers that the first-come first served queuing rules under the applications and queuing policy, in combination with the structure of the wholesale electricity market and reserve capacity mechanism, do not serve to promote efficient investment in the electricity network.

1584. Although the removal of the first-come first-served queuing rules from the proposed revised applications and queuing policy should lead to an improvement, the Authority considers any deficiencies of the wholesale electricity market and reserve capacity mechanism cannot be fully resolved through the queuing rules in the applications and queuing policy. As noted in the Authority’s final decision for the current access arrangement, this requires consideration in a broader review of regulatory arrangements for the electricity market that considers network planning processes, the functioning of the wholesale electricity market, the treatment of new investment under the Access Code, as well as the applications and queuing policy.

Priority of access applications lodged before the start of the third access arrangement period

1585. Section 5.7(i) of the Access Code requires that an applications and queuing policy must, if applicable, contain provisions setting out how access applications (or other requests for access to the covered network) lodged before the start of the relevant access arrangement period are to be dealt with.

1586. The proposed applications and queuing policy involves substantial changes to the current applications and queuing arrangements. This is in the context of there being a substantial number of applications currently being processed by Western Power and queued under provisions of the current applications and queuing policy.

1587. The Authority notes that Western Power considers existing applications will not be disadvantaged on the basis that under the proposed revised applications and queuing policy, those applications will not be treated as withdrawn and should be processed in the same time, or less, compared to the existing applications and queuing policy. Clause 2.4(b) specifically provides that an application made prior to the date of commencement of the proposed revised applications and queuing policy shall be deemed to have been made under the proposed applications and queuing policy with a priority date being the date it was given under the current policy.

1588. The Authority considers this view to be reasonable, provided such applicants are also free to pursue an applicant-specific solution if desired. This would enable applicants to either progress their application through the competing applicant group process which may result in reduced connection costs and thus progress an augmentation, or to continue to pursue an applicant-specific solution which is in effect the status quo.

1589. As discussed in paragraphs 1540 to 1545, the Authority has required an amendment to ensure the proposed applications and queuing policy makes provision for an applicant to have an application treated independently of any other application, providing the applicant is prepared to fully fund the solution. The Authority considers that, providing the relevant amendment is made, existing applicants will be no worse off under the proposed revised applications and queuing policy.

Other matters raised in submissions

1590. Submissions made to the Authority on the proposed applications and queuing policy address some issues not directly related to the requirements of section 5.7 of the Access Code.

1591. Griffin Energy's submission raises concerns over the ability of an existing user (with specific reference to Verve Energy) to retain contractual rights to unutilised transmission capacity, with a consequent inefficient use of the transmission network. The Authority has previously considered this matter in relation to proposals by Western Power during both the first and second access arrangement reviews for Western Power to have a right to unilaterally reduce a user's contracted capacity where that capacity is unutilised.

1592. The Authority's reasoning included the following points which are relevant to the concerns raised in Griffin Energy's submission:

- under the regulatory scheme established by the Access Code, where access contracts are based on rights to capacity at entry points and exit points, it would be unreasonable for a user to not be able to enter into a contract for capacity and, subject to continuing to pay the relevant tariffs for that capacity, to continue to hold the contracted capacity regardless of whether that capacity is used or not;
- the ability of a user to hold contracted capacity at entry points or exit points that are unused is consistent with efficient investment in the network as the user will generally make any such decision to hold unused capacity taking into account the cost of that capacity and the value of the option to utilise the capacity at some time in the future;
- under the regulatory scheme applying under the Access Code and where a user may be required to pay capital contributions for an augmentation of the network in order to contract for a certain amount of capacity at an entry or exit point, the ability of a user to hold contracted capacity that is unused is necessary for that user to make efficient decisions for the payment of capital contributions; and
- other remedies exist to address the holding by a user of unused capacity for anticompetitive purposes – the holding by a user of unused capacity for this purpose may constitute hindering or preventing access and be unlawful under section 115 of the *Electricity Industry Act 2004* or otherwise in contravention of Part IV of the *Trade Practices Act*.[391]

1593. Submissions from Griffin Power, Synergy and Perth Energy raised concerns over the relationship of the applications and queuing policy with an emerging consideration of whether generation should be connected to the network on a constrained or unconstrained basis. As noted in paragraph 145 above, the Authority is aware that consideration is being given to the merits of moving to a constrained network approach, however, this is not an issue within the scope of the access arrangement review process.

1594. In its submission, Pacific Hydro observes that:

> Solutions that meet the needs of a particular competing application group will be charged uniformly across all parties; however some solutions may only be relevant for specific developers resulting in a smearing of augmentation costs. This may not be a desirable outcome for developers who have good connection access.

1595. The Authority recognises that there will potentially be winners and losers in any methodology dealing with capacity augmentations and how the resultant costs are shared. However, to the extent that the proposed applications and queuing policy results in a more efficient overall solution, then the objectives of the Access Code are better achieved. Furthermore, as discussed above in paragraphs 1540 to 1545 above, applicants will be able to pursue an applicant-specific solution and the Authority has required amendments to the proposed applications and queuing policy to ensure that is the case.

[391] Economic Regulation Authority, 4 December 2009, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, pp. 62, 63.

Drafting Amendments

1596. In its review of the proposed revised applications and queuing policy the Authority noted a number of drafting issues that require amendment:

Definitions

The following phrases must be italicised as they are defined terms:

1. "reasonable and prudent person", wherever it appears in the policy; and
2. "confidential information", at the end of clause 6.1.

Clause 14.4(f)(ii)(B)

The full stop at the end of the clause should not be underlined.

Clause 24.10(a)

The word "unused" should not be italicised and "; and" should be deleted.

Clause 24A.3(b)

The word "its" on line 5 should be amended to "it", so that part of the clause reads:

> "......timing, cost and terms of it obtaining access......"

Clauses 24A.3(d) and (e)

The phrase "*Preliminary Access Offer*" on the last line of sub-clause (d), and in all places in sub-clause (e), should be lower case so that the term reads "*preliminary access offer*".

Required Amendment 77

The proposed revised access arrangement should be amended to incorporate the drafting amendments set out in paragraph 1596.

CONTRIBUTIONS POLICY

Access Code Requirements

1597. The contributions policy sets out the principles and processes for determining when a contribution will be required from a user, including for a network augmentation, and for determining the amount of the contribution. A "contribution" is defined in section 1.3 of the Access Code as a capital contribution, a non-capital contribution or a headworks charge.

1598. Section 5.1(h) of the Access Code requires that an access arrangement include a contributions policy, defined in section 1.3 of the Access Code as a policy in an access arrangement under section 5.1(h) dealing with contributions by users.

1599. The particular requirements for a contributions policy are set out in sections 5.12 to 5.17D of the Access Code:

5.12 The objectives for a contributions policy must be that:

(a) it strikes a balance between the interests of:

(i) contributing users; and

(ii) other users; and

(iii) consumers; and

(b) it does not constitute an inappropriate barrier to entry.

5.13 A contributions policy must facilitate the operation of this Code, including:

(a) sections 2.10 to 2.12; and

(b) the test in section 6.51A; and (ba) sections 5.14 and 5.17D; and

(c) the regulatory test.

5.14 Subject to section 5.17A and a headworks scheme, a contributions policy:

(a) must not require a user to make a contribution in respect of any part of new facilities investment which meets the new facilities investment test; and

(b) must not require a user to make a contribution in respect of any part of non- capital costs which would not be incurred by a service provider efficiently minimising costs; and

(c) may only require a user to make a contribution in respect of required work;

and

(d) without limiting sections 5.14(a) and 5.14(b), must contain a mechanism designed to ensure that there is no double recovery of new facilities investment or non-capital costs.

5.15 A contributions policy must set out:

(a) the circumstances in which a contributing user may be required to make a contribution; and

(b) the method for calculating any contribution a contributing user may be required to make; and

(c) for any contribution:

(i) the terms on which a contributing user must make the contribution; or

(ii) a description of how the terms on which a contributing user must make the contribution are to be determined.

5.16 A contributions policy may:

(a) be based in whole or in part upon the model contributions policy, in which case, to the extent that it is based on the model contributions policy, any matter which in the model contributions policy is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model contributions policy; and

(ii) sections 5.12 to 5.15; and

(iii) the Code objective;

and

(b) be formulated without any reference to the model contributions policy and is not required to reproduce, in whole or in part, the model contributions policy.

5.17 The Authority:

(a) must determine that a contributions policy is consistent with sections 5.12 to 5.15 and the Code objective to the extent that it reproduces without material omission or variation the model contributions policy; and

(b) otherwise must have regard to the model contributions policy in determining whether the contributions policy is consistent with sections 5.12 to 5.15 and the Code objective.

5.17A Despite section 5.14, Electricity Networks Corporation may require a contribution for Appendix 8 work of up to the maximum amount determined under Appendix 8 for the relevant type of Appendix 8 work.

5.17B From 1 July 2007 until the first revisions commencement date for the Western Power Network access arrangement, section 5.17A prevails over any inconsistent provisions of the Western Power Network access arrangement.

5.17C Despite section 5.14, the Authority may approve a contributions policy that includes a “headworks scheme” which requires a user to make a payment to the service provider in respect of the user’s capacity at a connection point on a distribution system because the user is a member of a class, whether or not there is any required work in respect of the user.

5.17D A headworks scheme must:

(a) identify the class of works in respect of which the scheme applies, which must not include any works on a transmission system or any works which effect a geographic extension of a network; and

(b) not seek to recover headworks charges in an access arrangement period which in aggregate exceed 1 per cent of the distribution system target revenue for the access arrangement period; and

(c) identify the class of users who must make a payment under the scheme; and

(d) set out the method for calculating the headworks charge, which method:

(i) must have the objective that headworks charges under the headworks scheme will, in the long term, and when applied across all users in the class referred to in section 5.17D(c), recover no more than the service provider's costs (such as would be incurred by a service provider efficiently minimising costs) of any headworks; and

(ii) must have the objective that the headworks charge payable by one user will differ from that payable by another user as a result of material differences in the users' capacities and the locations of their connection points, unless the Authority considers that a different approach would better achieve the Code objective; and

(iii) may use estimates and forecasts (including long term estimates and forecasts) of loads and costs; and

(iv) must contain a mechanism designed to ensure that there is no double recovery of costs in all the circumstances, including the manner of calculation of other contributions and tariffs; and

(v) may exclude a rebate mechanism (of the type contemplated by clauses A4.13(d) or A4.14(c)(ii) of Appendix 4) and may exclude a mechanism for retrospective adjustments to account for the difference between forecast and actual values.

Current Access Arrangement

1600. A contributions policy is contained in Appendix 3 of the current access arrangement.

Proposed Revisions

1601. In its proposed revised access arrangement information, Western Power states that its proposed revisions to the contributions policy will see no material departure to the current form and operation of the policy. Western Power has proposed the following revisions:

- section 5.2(a) of the Contributions Policy has been revised such that any headworks costs associated with a headworks scheme and any incremental revenue taken account of by the new facilities investment test are excluded when contributions payable are calculated;

- section 6(e) of the contributions policy ,which stated that when calculating a headworks contribution the amount likely to be recovered as new revenue should be deducted, has been deleted;
- section 6 of the Distribution Headworks Methodology has been revised such that the headworks price list will be inflated on an annual basis (using March CPI data) rather than quarterly and the price list will be reviewed prior to the start of each access arrangement period (based on distribution construction cost estimates) rather than annually; and
- Appendix D of the current Distribution Headworks Methodology has been removed as it relates to a Government rebate subsidy scheme to residential and commercial applications impacted by the headworks scheme that is no longer in operation.

1602. Western Power has also proposed to introduce a distribution low voltage connection scheme with its original intention being to submit an in-period (current access arrangement) submission to seek approval for the scheme. Western Power prepared its AA3 proposed revisions assuming that the in-period submission would occur prior to it submitting the proposed revisions for AA3 and has included the new scheme in its proposed revised Contributions Policy. This matter is discussed further below.

Submissions

Contributions Policy

1603. In its submission Perth Energy considers this is an opportune time for the Authority to deal with some of the inefficiencies and complexities it believes have materialised in the capacity market within the WEM flowing directly from the application of Western Power's capital contribution policy as set out in the Access Arrangement. Perth Energy raises a number of issues with the current capital contribution policy and suggests that a potential way forward would be to move to a shallow-only charging policy. Perth Energy has put forward options around using location specific use of system charges. Perth Energy proposes that if the access is to be used for supply to general retail loads in the SWIS, i.e. without one or more specific foundation loads, then shallow only charges should apply; if the access is designed for one dedicated load, the entire contribution should be made by that load; and if access is for a mix of dedicated loads and general retail market, then Western Power could apply a shared allocation.

1604. Landfill Gas and Power's submission supports Western Power's proposed changes to the contributions policy.

1605. WALGA submits that timely availability of network capacity to support developments, particularly in regional areas, and the prices proposed by Western Power for network expansion/augmentation are of concern to local authorities. WALGA considers Western Power's ability to be responsive to a dynamic property development market is important to all land developers, including Local Governments.

Headworks Scheme

1606. The submission from the Office of Energy notes that Western Power explicitly states that “[the] methodology explains how the requirements of sections 5.17D(i), (ii) and (iii) [of the Access Code] have been met in the Contributions Policy but makes no mention of the requirements under 5.17D(d)(iv) and (v)” and queries what Western Power’s reasons are for not considering these requirements.

1607. The Office of Energy also considers it would be helpful if Western Power provided reasoning for its amendments to the Code definitions of “transmission system” and “distribution system” in its Distribution Headworks Methodology.

Distribution Low Voltage Connection Scheme Methodology

1608. Synergy’s submission notes that a proposed Code amendment allowing for an increase in the headworks charges that Western Power may directly recover from consumers who are subject to Western Power’s proposed Distribution Low Voltage Connection Scheme (**DLVCS**), is yet to be approved and hence the scheme should not be considered as part of the AA3 revisions.

1609. The National Electrical and Communications Association supports the proposed distribution low voltage connection scheme as providing greater transparency whilst removing the disparity in pricing for customers who request the same scope of works yet are charged very different prices.

1610. Submissions from FINBAR and the Property Council of Australia both raise similar points and are concerned particularly with the potential impact on the competitiveness of multi-unit development in Western Australia. Specific points raised include:

- there is no effective means to gauge the risk of having Contributions Policy section 7.5 (exclusion from DLVCS) applied to a project, thus providing no certainty to a developer when considering the initial feasibility of a project;
- the revenue offset is not clearly set out and the current arrangements include the inequitable exclusion of multi-residential development from having a revenue offset applied to the headworks costs; and
- the formula to be used for calculating the level of security.

1611. The Office of Energy’s submission raised some points relating to drafting:

- The Contributions Policy defines “headworks scheme” as meaning “the scheme described in clause 6 of this *contributions policy*”. Clause 6 only refers to the distribution headworks scheme. This definition therefore does not include Western Power’s distribution low voltage connection scheme which is described in clause 7 of the contributions policy.
- The Distribution Headworks Methodology states that “headworks has the same meaning given to it in the Contributions Policy”. However, the definition in the DLVCS Methodology does not contain the reference to HV (or high voltage) like the Contributions Policy definition does. The high voltage reference may have implications for the classification of the proposed distribution low voltage connection scheme as a headworks scheme.

Considerations of the Authority

1612. In considering the proposed revised Contributions Policy, the Authority has given attention to the revisions proposed by Western Power as well as to whether, in view of practical experience, the provisions of the capital contributions policy under the current access arrangement are consistent with the requirements of the Access Code. In doing so, the Authority has had regard to submissions made on the proposed access arrangement revisions. The considerations of the Authority are set out below under the following headings:

- current provisions of the capital contributions policy; and
- proposed revisions to be incorporated into the contributions policy.

1613. As noted by Synergy, currently the Access Code does not permit the proposed distribution low voltage scheme as it falls above the threshold set for such schemes as set out in section 5.17D(b) of the Code. Until such an amendment is made, the Authority is unable to approve the scheme.

1614. The Authority understands a proposed Code amendment to section 5.17D(b) is currently awaiting approval. Once such an amendment is gazetted, the Authority will give consideration to the proposed scheme. In the interim the Authority has drawn attention to the points raised in public submissions in relation to the proposed scheme and recommends Western Power continue to work with stakeholders to resolve any issues.

1615. As the Authority is unable to approve the proposed distribution low voltage scheme, all references to it will need to be removed from the proposed revised access arrangement.

Required Amendment 78

The proposed revised access arrangement must be amended to delete all reference to the proposed distribution low voltage scheme.

Current Provisions of the Capital Contributions Policy

1616. Perth Energy's submission to the Authority on the proposed access arrangement revisions indicate that there are practical difficulties with broad principles and particular provisions of the current capital contributions policy that are proposed to be maintained in the contributions policy for the third access arrangement period. The particular matters raised by Perth Energy include:

- inefficiencies and complexities it believes have materialised in the capacity market within the WEM flowing directly from the application of Western Power's capital contribution policy as set out in the Access Arrangement;
- issues with the current capital contribution policy and a suggestion that a potential way forward would be to move to a shallow-only charging policy;
- options around using location specific use of system charges; and
- a proposal that if the access is to be used for supply to general retail loads in the SWIS, i.e. without one or more specific foundation loads, then shallow

only charges should apply. If the access is designed for one dedicated load, the entire contribution should be made by that load. If access is for a mix of dedicated loads and general retail market, then Western Power could apply a shared allocation.

1617. These matters are interrelated and are addressed by the Authority as follows.

1618. The primary determinant of the amount of a contribution that can be required in respect of new facilities investment to augment a network is the amount of the new facilities investment that does not satisfy the new facilities investment test under section 6.52 of the Access Code. Under section 5.14 of the Access Code, a contributions policy must not require a user to make a contribution in respect of any new facilities investment that meets the new facilities investment test, with the exception of contributions required under a "headworks scheme" or new facilities investment for works of certain types specified in Appendix 8 of the Access Code.

1619. Where the provision of a service to a user will require works for "deep" augmentation of a network, the amount of a contribution to be required in respect of the new facilities investment for these works will depend upon how much of the new facilities investment is determined as meeting the new facilities investment test.

1620. The current capital contributions policy and the proposed contributions policy are consistent with this requirement by indicating, at clause 2(c)(i), that a contribution in respect of new facilities investment may only be required in respect of an amount that does not meet the new facilities investment test.

1621. In determining the amount of a contribution to be required in respect of new facilities investment, other than for exceptions provided for under Appendix 8 of the Access Code and under a headworks scheme, Western Power must necessarily determine the amount of the new facilities investment that meets the new facilities investment test. As Western Power may only require contributions in respect of new facilities investment that do not satisfy the test, this ensures there is not double recovery of the costs of the new facilities investment.

1622. Applying the new facilities investment test for the purposes of determining the amount of a contribution involves addressing the individual components of the test:

- ensuring that the forecast amount of the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs;
- determining whether the amount of anticipated incremental revenue for the new facility (which would include incremental revenue from both the user potentially liable for the contribution and from other users of the network) is expected to at least recover the forecast amount of the new facilities investment;
- determining whether all or part of the new facilities investment falls under a "modified test" under sections 6.52(b)(i)B and 6.53 of the Access Code;
- determining the nature and value of any net benefits arising from the new facilities investment, which might be diverse in nature and include such benefits as, for example, increased reliability of network services and improved outcomes in electricity markets; and

- determining whether the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

1623. While not indicated to this level of detail in the proposed contributions policy, the Authority is satisfied that these requirements are implicit in the provisions of clause 5.2 of the proposed contributions policy that sets out the calculation of a contribution and that indicates that a contribution in respect of new facilities investment excludes any amount that meets the new facilities investment test.

1624. Whether or not contributions should be charged in respect of new facilities investment for deep augmentations of the network is a matter to be determined according to a calculation of the amount of the new facilities investment that satisfies the new facilities investment test. Western Power necessarily undertakes this determination in the first instance, although any determination is ultimately subject to approval by the Authority. As part of an approval, the Authority will assess whether Western Power has appropriately applied the new facilities investment test, including whether Western Power has appropriately taken into account any benefits of deep augmentations of the network to those who generate, transport and consume electricity in the network.

Current Provisions of the Headworks Scheme

1625. The Office of Energy notes that Western Power explicitly states that "[the] methodology explains how the requirements of sections 5.17D(d)(i), (ii) and (iii) [of the Access Code] have been met in the Contributions Policy. It makes no mention of the requirements under 5.17D(d)(iv) and (v). The Office of Energy has queried what Western Power's reasons are for not considering these requirements.

> 5.17D(d) (iv) must contain a mechanism designed to ensure that there is no double recovery of costs in all the circumstances, including the manner of calculation of other contributions and tariffs
>
> 5.17D (d)(v) may exclude a rebate mechanism (of the type contemplated by clauses A4.13(d) or A4.14(c)(ii) of Appendix 4) and may exclude a mechanism for retrospective adjustments to account for the difference between forecast and actual values.

1626. In its Final Decision for the current access arrangement, the Authority required the following:

> Final Decision Amendment 42
>
> The proposed access arrangement revisions should be amended such that clause 6 of the contributions policy sets out:
>
> - the method or calculation and assumptions applied in determining the amount of costs to be recovered by headworks contributions;
> - the method or calculation and assumptions applied in determining the allocation of costs across a forecast of connections to the network and determining the magnitude of headworks contributions;
> - the procedures or methods applied by Western Power to ensure that headworks contributions will, in the long term, recover no more than Western Power's costs of the headworks; and

- a mechanism, which may involve a system of accounting records, to ensure that any amount of the costs of the headworks recovered by headworks contributions are not also recovered, or sought to be recovered, through other contributions or through tariffs for services.

1627. In response to the current access arrangement Final Decision, Western Power:

- amended clause 6 of the contributions policy to reference a new appendix to the access arrangement (Appendix 9 – Distribution Headworks Methodology, relabelled as Appendix C.2 in the proposed revised access arrangement), which set out the method used to determine the headworks prices that may apply under the contributions policy;
- amended clause 6.2(b) of the contributions policy to indicate that where a headworks contribution is made by an applicant, no further contribution should be required from the applicant in respect of headworks; and
- added a new clause 6.2(c) to the contributions policy, which stated that a headworks contribution is a capital contribution (as defined in the Access Code).

1628. In its Further Final Decision, the Authority noted that it was satisfied that the appendix adequately set out the method for calculating the headworks charge. The Authority was also satisfied that the amendment to clause 6.2(b) adequately ensured that headworks funded under the headworks scheme, are not also funded by other contributions from users. Furthermore, the Authority noted that, taking into account the requirements under section 6.51A of the Access Code for consideration of capital contributions in adding amounts of new facilities investment to the capital base, the Authority was satisfied that clause 6.2(c) prevented any amount of headworks costs that are financed by headworks contributions from also being recovered through tariffs for services.[392]

1629. The Authority continues to be satisfied, for the above reasons, that appropriate mechanisms are in place to ensure there is no double recovery of costs in relation to headworks costs and contributions as required by 5.17D(d)(iv).

1630. With regard to section 5.17D(d)(v) the Authority notes there is no requirement under the Code for a headworks scheme to include a rebate mechanism or a mechanism to retrospectively adjust for differences between forecast and actual values.

1631. The Office of Energy's submission queries the definitions of "distribution system" and "transmission system" in the Distribution Headworks Methodology. The Authority notes these definitions are unchanged from the current access arrangement and are consistent with Western Power's Contributions Policy.

Proposed Revisions to the Contributions Policy

1632. The Authority's considerations on Western Power's proposed revisions to the Contributions Policy and Distribution Headworks Methodology are set out below.

[392] Under this provision, Western Power is required to ensure that headworks charges are deducted from new facilities investment in determining the amount of new facilities investment that can be added to Western Power's regulated capital base (that is, the amount of new facilities investment that satisfies the new facilities investment test). This is in accordance with the general scheme proposed by Western Power for the treatment of capital contributions in determining its regulated capital base.

Calculation of Contributions Payable

1633. Western Power notes that it has amended sections 5.2(a) and 6(e) of the Contributions Policy to more clearly relate the method of calculation of contributions under the Contributions Policy with the operation of the Distribution Headworks Methodology. The proposed amendments are underlined as follows:

> 5.2 The contribution payable in respect of any works to which this policy applies is calculated by:
>
> (a) determining the appropriate portion of any of the forecast costs of the works (<u>excluding headworks with respect to the headworks scheme</u> …) which do not meet the new facilities investment test (<u>excluding, to avoid doubt, the incremental revenue test as per section 6.52(b)(i)(A) of the Code</u>)…
>
> …
>
> (e) deducting the amount likely to be recovered in the form of new revenue gained from providing covered services to the applicant, or, if the applicant is a customer, to the customer's retailer, as calculated over the reasonable time, at the contributions rate of return…

1634. Western Power states section 5.2(a) has been revised to make clear that any headworks costs associated with a headworks scheme are excluded when calculating contributions under the Contribution Policy. As such costs will be covered by headworks contributions it would be double counting to also include them in an assessment of a contribution under the Contribution Policy.

1635. Western Power states the amendment to section 5.2(a) in relation to incremental revenue is to make clear that incremental revenue is only deducted at section 5.2(e) and not at section 5.2(a) as well, as this would result in double counting.

1636. The Authority agrees the amendments proposed by Western Power to section 5.2 serve to clarify the intention of the policy.

1637. Western Power proposes deleting section 6.3(e) of the Contributions Policy which stated that when calculating a headworks contribution the amount likely to be recovered as new revenue should be deducted. Western Power states that the text should be removed to avoid an impression that the calculation of a headworks contribution should deduct expected new tariff revenue from the forecast costs in the calculation of a headworks contribution. Western Power considers this is necessary because expected new tariff revenue is deducted from forecast costs in the calculation of contributions under the contributions policy and so should not also be deducted again through the Distribution Headworks Methodology.

1638. The Authority agrees the proposed deletion of section 6.3(e) is appropriate to avoid the suggestion that new tariff revenue is included twice in the calculation of contributions. However, the Distribution Headworks Methodology, in particular Appendix C, *Revenue Offsets*, is still potentially confusing as it notes that price lists for headworks charges take into account standard revenue offsets. Further clarification is needed to ensure clarity for customers in relation to how revenue offsets are calculated and how they are taken account of when determining headworks contributions.

Required Amendment 79

The Distribution Headworks Methodology and Contribution Policy must clarify how revenue offsets are calculated and how they are taken account of when determining headworks contributions.

Headworks Price List Review Process

1639. Western Power has proposed amendments to simplify and reduce the time and resources needed to update the headworks price list. Western Power considers the current requirement to adjust prices quarterly and review cost estimates annually is excessive given the revenue generated (around $1 million to $2 million annually) and the substantial time and resources involved in conducting a review of distribution construction cost estimates. Western Power notes that a review of the Distribution Headworks Methodology (**DHM**) distribution construction cost estimates takes a network planner around three months to complete.

1640. Western Power has proposed that the headworks price list will be:

- inflated for CPI on an annual basis; and
- reviewed prior to the commencement of each access arrangement period based on distribution cost estimates, to ensure that movements in costs or efficiencies have been accounted for within prices.

1641. The Authority agrees there should to be an appropriate balance between the need to update prices to reflect changes in the underlying cost structures and the effort and cost involved in the price setting process. For the level of revenue involved the current amount of effort, as outlined by Western Power, would appear to be greater than required.

1642. On that basis the Authority considers Western Power's proposal to index prices each year by CPI and review the level of charges at each access arrangement review is reasonable.

1643. However, the Authority considers this process would be more transparent if the charges were set out in the DHM and an explanation given of any significant changes to those charges.

Required Amendment 80

The Distribution Headworks Methodology must include a copy of the relevant price lists together with an explanation of any significant changes to those charges compared with the previous period.

Appendix D of Distribution Headworks Methodology

1644. On the basis of Western Power's advice that the Government rebate subsidy scheme for residential and commercial applications impacted by the headworks scheme is no longer in operation, the Authority agrees Appendix D is no longer required.

TRANSFER AND RELOCATION POLICY

Access Code Requirements

1645. Section 5.1(i) of the Access Code requires that an access arrangement include a transfer and relocation policy. The particular requirements for a transfer and relocation policy are set out in sections 5.18 to 5.24 of the Access Code:

5.18 A transfer and relocation policy:

(a) must permit a user to make a bare transfer without the service provider‘s consent; and

(b) may require that a transferee under a bare transfer notify the service provider of the nature of the transferred access rights before using them, but must not otherwise require notification or disclosure in respect of a bare transfer.

5.19 For a transfer other than a bare transfer, a transfer and relocation policy:

(a) must oblige the service provider to permit a user to transfer its access rights and, subject to section 5.20, may make a transfer subject to the service provider‘s prior consent and such conditions as the service provider may impose; and

(b) subject to section 5.20, may specify circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.19(a).

5.20 Under a transfer and relocation policy, for a transfer other than a bare transfer, a service provider:

(a) may withhold its consent to a transfer only on reasonable commercial or technical grounds; and

(b) may impose conditions in respect of a transfer only to the extent that they are reasonable on commercial and technical grounds.

5.21 A transfer and relocation policy:

(a) must permit a user to relocate capacity at a connection point in its access contract to another connection point in its access contract, (a ‘relocation’) and, subject to section 5.22, may make a relocation subject to the service provider‘s prior consent and such conditions as the service provider may impose; and

(b) subject to section 5.22, may specify in advance circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.21(a).

5.22 Under a transfer and relocation policy, for a relocation a service provider:

(a) must withhold its consent where consenting to a relocation would impede the ability of the service provider to provide a covered service that is sought in an access application; and

(b) may withhold its consent to a relocation only on reasonable commercial or technical grounds; and

(c) may impose conditions in respect of a relocation only to the extent that they are reasonable on commercial and technical grounds.

5.23 An example of a thing that would be reasonable for the purposes of sections 5.20 and 5.22 is the service provider specifying that, as a condition of its agreement to a transfer or relocation, the service provider must receive at least the same amount of revenue as it would have received before the transfer or relocation, or more revenue if tariffs at the destination point are higher.

5.24 Section 5.23 does not limit the things that would be reasonable for the purposes of sections 5.20 and 5.22.

1646. The Access Code does not provide a model transfer and relocation policy.

Current Access Arrangement

1647. The current access arrangement includes a transfer and relocation policy at Appendix 2.

1648. The transfer and relocation policy of the current access arrangement is indicated at clause 2.1 to apply to any access contract unless otherwise explicitly stated in the access contract, and includes:

- definitions of terms and rules of interpretation (clause 1);
- indication that the transfer and relocation policy applies to any access contract unless otherwise explicitly stated in the access contract (clause 2) and prohibition of any transfer of rights under an access contract except as allowed for under the transfer and relocation policy (clause 3);
- provision for bare transfers of rights under an access contract (clause 4);
- provision for assignments of rights under an access contract other than a bare transfer, subject to consent of Western Power (clause 5); and
- provision for a relocation by a user of contracted capacity at one connection point to another connection point, where the user has an access contract for both connection points (clause 6).

Proposed Revisions

1649. Western Power has moved the transfer and relocation policy to Appendix D of the proposed revised access arrangement but otherwise has not proposed any revisions to the policy. It notes that the policy has had limited use during the current access arrangement and that it has not identified any problems with its operation.

Submissions

1650. None of the submissions made to the Authority on the proposed access arrangement revisions address the transfer and relocation policy.

Considerations of the Authority

1651. Taking into account that Western Power has not proposed any revisions to the transfer and relocation policy and the absence of submissions on the policy, the

Authority considers that the transfer and relocation policy of the proposed access arrangement revisions are consistent with the requirements of the Access Code.

SUPPLEMENTARY MATTERS

Access Code Requirements

1652. Section 5.1(k) of the Access Code requires that an access arrangement include provisions dealing with supplementary matters under sections 5.27 and 5.28.

1653. Section 5.27 indicates that supplementary matters comprise:

(a) balancing; and

(b) line losses; and

(c) metering; and

(d) ancillary services; and

(e) stand-by; and

(f) trading; and

(g) settlement; and

(h) any other matter in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Code objective.

1654. Section 5.28 of the Access Code requires that the supplementary matters be dealt with in the access arrangement in accordance with other relevant regulatory requirements including written laws, the Wholesale Electricity Market Rules and the Technical Rules.

Current Access Arrangement

1655. Supplementary matters are dealt with in clauses 10.1 to 10.9 of the current access arrangement, addressing the particular matters listed under section 5.27 of the Access Code. These matters are dealt with by reference to the Wholesale Electricity Market Rules and Metering Code.

Proposed Revisions

1656. In the proposed revised access arrangement, supplementary matters are dealt with in clauses 9.1 to 9.7.1. Western Power has not proposed any revisions from the current access arrangement.

Submissions

1657. None of the submissions made to the Authority on the proposed access arrangement revisions address the supplementary matters.

Considerations of the Authority

1658. Taking into account the absence of proposed revisions to the section of the access arrangement dealing with supplementary matters and the absence of submissions addressing this element of the access arrangement, the Authority considers that the proposed access arrangement revisions are consistent with the requirements of sections 5.1(k), 5.27 and 5.28 of the Access Code.

APPENDICES

Appendix 1: Summary of Required Amendments

Required Amendment 1

Section 1.1.2 of the proposed revised access arrangement must be amended to include the underlined text as follows:

"This access arrangement sets out the terms and conditions under which Western Power will provide users and applicants with access to the Western Power Network…"

Required Amendment 2

Section 1.5.1(e) of the proposed revised access arrangement must be deleted and sections 1.5.1 (f) to 1.5.1 (i) renumbered accordingly.

Required Amendment 3

The proposed revised bi-directional reference tariffs (C1, C2, C3 and C4) must not be extended to battery storage and electrical vehicle systems unless the issues identified in paragraphs 105 to 113 above are resolved.

Required Amendment 4

The proposed revised access arrangement values for TRt and DRt must be amended to reflect the Authority's amended revenue values for Transmission and Distribution (as shown in last row of Table 4 and Table 5).

Required Amendment 5

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure which applies real labour and material escalation rates to the amended values in Table 32 and Table 33.

Required Amendment 6

The proposed revised access arrangement should be amended to reflect a forecast of operating expenditure as indicated in Table 37.

Required Amendment 7

The actual capital expenditure for 2009/10 and 2010/11 must be restated to exclude expenditure relating to cancelled or deferred projects and to reverse the statutory inventory adjustments in both years.

Required Amendment 8

The proposed revised access arrangement should be amended to reflect the values shown in Table 41 above.

Required Amendment 9

Western Power's proposed adjustment to include the cost of inventory in the capital base must be removed.

Required Amendment 10

Western Power must establish the value of any redundant assets included in its current asset base and to include accelerated depreciation to fully write them off.

Required Amendment 11

The proposed revised access arrangement must be amended such that the 'time value of money adjustment' for mid-year capital expenditure timing is removed from the rolled forward capital base and notional capital base for AA3.

Required Amendment 12

Expenditure relating to investment from prior periods does not meet the new facilities investment test and must not be included in the capital base.

Required Amendment 13

The opening capital base for 1 July 2012 in the proposed revised access arrangement must be amended to reflect the values in Table 43 and Table 44 above.

Required Amendment 14

The proposed access arrangement revisions must be amended to include expenditure relating to wood pole management in the investment adjustment mechanism.

Required Amendment 15

The proposed access arrangement revisions must be amended to incorporate a forecast of capital expenditure as listed in Table 62.

Required Amendment 16

Western Power's proposed adjustment to the capital base for the third access arrangement period for changes to the stock of inventory must be removed.

Required Amendment 17

The proposed revised access arrangement must be amended to remove any amounts in relation to a mid-year timing assumption.

Required Amendment 18

Western Power's revised access arrangement must be amended to reflect a 20 year economic life for depreciation purposes for transmission SCADA and communications.

Required Amendment 19

Western Power must establish the value of any redundant assets included in its notional capital base for the third access arrangement period and include accelerated depreciation to fully write them off.

Required Amendment 20

Western Power's Proposed Revisions must be amended to adopt a real post-tax rate of return of 3.87 per cent.

Required Amendment 21

No amounts in relation to tax on capital contributions must be included in Target Revenue.

Required Amendment 22

The amounts included in target revenue for working capital must be amended to the values in Table 93 and Table 94 .

Required Amendment 23

The Authority requires that Western Power model its tax liabilities explicitly, as a separate nominal 'building block', applying the method set out in this Draft Decision.

To this end, the Authority requires that Western Power amend the tax liabilities for the purposes of determining its maximum annual revenue requirements to those estimated by the Authority as set out in Table 4 and Table 5.

Required Amendment 24

The Authority requires that Western Power determine the forward looking efficient costs of raising equity according to the method set out in this Draft Decision.

To this end, the Authority requires that Western Power amend the cost of raising equity for the purposes of determining the revenue requirement to those estimated by the Authority as set out in Table 65 and Table 66 .

Required Amendment 25

The proposed revised access arrangement must be amended to include an adjustment to target revenue for the third access arrangement period taking account of any under-recovery or over-recovery of revenue under the revenue cap in 2010/11 and 2011/12.

Required Amendment 26

No adjustment to target revenue for the third access arrangement period should be made in relation to unforseen events.

Required Amendment 27

The reward in relation to the service standard adjustment mechanism for the distribution service must be amended to use the Authority's approved post tax WACC of 3.87 per cent).

Required Amendment 28

Section 7.5 of the proposed access arrangement must be amended to include an adjustment resulting from any differences between forecast and actual network performance in 2011/12, based on the service standard benchmarks set for the second access arrangement period – to be made to target revenue at the beginning of AA4.

Required Amendment 29

The proposed access arrangement must be amended to recover deferred revenue over ten years and include a similar provision to the existing access arrangement regarding how this will be reviewed at AA4.

Required Amendment 30

The 'minimum standard' Circuit Availability service standard benchmark must be set at 97.6 per cent. This is the estimated 2.5 per cent PoE level derived from the application of a Weibull distribution to the last five years of the historic Circuit Availability data, with a 0.2 per cent reduction to reflect forecast impacts of additional transmission network capital works during AA3.

Required Amendment 31

To warrant the resources involved, and to relate the measure to actual performance, Western Power must include in the transmission Individual Customer Service service standard benchmark measure a reporting element relating to the outcomes of the satisfaction survey. This could be achieved by amending the definition of this measure to be:

The percentage of users over a 12 month period procuring a reference service A11 or B2 (after exclusions) that have:

- an account manager for the full 12 month period;
- an annually reviewed customer service management plan;
- participated in an annual satisfaction survey; and
- rated the overall performance of Western Power as satisfactory, good or excellent, but not unsatisfactory or poor.

Otherwise, this measure should not be implemented.

Required Amendment 32

The proposed access arrangement revisions must be amended to reinstate the service standard benchmarks for:

- transmission circuit System Minutes Interrupted – for meshed (less critical) and radial (more critical) circuits;
- Loss of Supply Event frequency, specified as a number of loss of supply events in a one year period with benchmarks specified for events of low and high duration measured as system minutes interrupted; and
- Average Outage Duration, measured in minutes.

Table 114 provides the relevant SSBs calculated by the Authority, based on data supplied by Western Power.

Required Amendment 33

The definition of the SAIDI and SAIFI service standard benchmark measures must be revised to include distribution network events only.

Required Amendment 34

Western Power is required to update its analysis for the SAIDI and SAIFI service standard benchmark measures to base the service standard benchmarks on the most recent three years of data (Table 115 provides the Authority's estimates).

Required Amendment 35

The Authority requires that for the Call Centre Performance service standard benchmark measure:

• The definition point 'First speaking with a person in 30 seconds or less' be amended to:

– 'First speaking with a person in 30 seconds or less, but excluding the time that the caller is connected to an automated interactive service (to a maximum of three minutes) that provides substantive information or elicits the caller's postcode, and which informs within the first 30 seconds that the call will be responded to by a human operator within three minutes.'

• The definition point 'First receiving an automated interactive message service message in 30 seconds or less' be deleted.

• The definition point 'The fault call response time commences when the postcode is automatically determined or when a valid postcode is entered by the caller or when the call is placed in the queue to be responded to by a human operator' be amended to:

– 'The fault call response time commences when the call first enters the call centre and starts ringing.'

The Authority requires the exclusions be defined as follows:

One or more of:

• Calls abandoned by a caller in 4 seconds or less of their postcode being automatically determined or when a valid postcode is entered by the caller.

• Calls abandoned during the first three minutes of an automated message.

• Calls abandoned by a caller in 30 seconds or less of the call being placed in the queue to be responded to by a human operator.

• All telephone calls received on a major event day which is excluded from SAIDI and SAIFI.

• A fact or circumstance beyond the control of Western Power affecting the ability to receive calls to the extent that Western Power could not contract on reasonable terms to provide for the continuity of service.

Required Amendment 36

The Authority requires that Western Power remove transmission network Circuit Availability as a distribution network service standard benchmark measure.

Required Amendment 37

Western Power is required to collect monthly data for the average number of momentary interruptions of one minute or less per distribution network customer for each of the distribution sub-classes (CBD, Urban, Rural short and Rural long), and report these as part of its annual service standards benchmarks report to the Authority. This would provide a basis for establishing service standard benchmarks and service standard targets for the fourth access arrangement period for a Momentary Average Interruption Frequency Index measure.

Required Amendment 38

Only those exclusions that are approved by the Authority in the access arrangement may be included for the purposes of the service standards measures. The proposed clause 4.5.2 must be removed.

Required Amendment 39

The proposed revised access arrangement should include a service standard measuring compliance with Western Power's Customer Charter. The benchmark must be set at 100 per cent.

Required Amendment 40

The proposed revised Price List and Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision.

Required Amendment 41

Clauses 5.6.1 and 5.7.1 of the proposed revised access arrangement must be amended to be consistent with clause 5.27 and 5.38 of the current access arrangement.

Required Amendment 42

The proposed revised Price List for 2012/13 must be amended to include revenue from standby services in forecast transmission revenue.

Required Amendment 43

The proposed revised access arrangement must be amended to explain how the revenue cap will be allocated between reference and non reference access services.

Required Amendment 44

Western Power must revise the specification of the adjustment parameters in the side constraints for transmission and distribution to make them consistent.

Required Amendment 45

The estimated incremental and stand-alone revenue included in the proposed revised Price List Information for 2012/13 must be amended to be consistent with the transmission network revenue cap and distribution network revenue cap approved by the Authority in this Draft Decision. Western Power should include commentary to explain any material variations in its estimate of incremental and stand-alone costs compared with the current 2011/12 Price List Information.

Required Amendment 46

All proposed tariffs for 2012/13 must be set between incremental and stand-alone costs in order to comply with section 7.3 of the Access Code.

Required Amendment 47

Western Power's proposed side constraint must apply from the first year of the third access arrangement.

Required Amendment 48

Western Power's proposed additions to streetlight asset types must ensure existing assets are not charged on a higher band compared with the current access arrangement.

Required Amendment 49

Western Power must provide a clearly stated methodology for making this adjustment which is based on the scaling factors approved by the Authority in this draft decision and includes details of how actual scaling factors will be verified.

Required Amendment 50

Western Power must amend its proposed revision to clarify how, in the event that service standard benchmarks are not achieved, it will be determined how and to what extent there is a relationship between costs savings and the underperformance on service standards.

Required Amendment 51

Western Power should establish the SSAM formula as follows:

$SSD_t = (SST_t – SSA_t) – AF^* (SST_{t-1} – SSA_{t-1})$ for the first and subsequent years of the AA

where:

SSD_t is the service standard difference in year t, and SST_{t-1} is the service standard difference in year t-1;

SST is the SSAM target;

SSA_t is the actual service performance in year t, and SSA_{t-1} is the actual service performance in year t-1, with respect to the SSAM measure;

AF is the 'attenuation factor' that takes the value 0.6.

Required Amendment 52

The Circuit Availability target must be set at 98.0 per cent. This is the 50 per cent PoE level derived from the application of a Weibull distribution to the last five years of historic data, but with a reduction of 0.2 per cent included.

Required Amendment 53

The System Minutes interrupted (meshed and radial networks) measures must be retained as SSAM incentive measures. The SSAM SST for these measures should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimates).

Required Amendment 54

The Loss of Supply Event Frequency measures must be retained as SSAM incentive measures. The SSAM SSTs should be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimates).

Required Amendment 55

The Average Outage Duration measure must be retained as SSAM incentive measures. The SSAM SST must be set at the 50 per cent PoE level based on best fit statistical distribution applied to the most recent five years of historic data (see Table 114 for the Authority's estimate).

Required Amendment 56

Western Power must:

- increase the transmission revenue at risk to 1 per cent of the annual average maximum transmission revenue and the potential reward to 1 per cent of the annual average maximum transmission revenue, taking account of the revisions to allowable transmission revenue set out in this draft decision;

- apply separate incentive penalty and reward rates where non-normal distributions are applied, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively;

- adopt the weightings set out in Table 120 to allocate the revenue at risk across the various measures.

Required Amendment 57

Western Power must:

- adopt revised estimates that remove the transmission network events from the SAIDI and SAIFI measures;

- base the targets on the most recent three years of data – the Authority's estimates of these revised SSTs are set out in row 7 of Table 121 and Table 122 (see also Table 115).

Required Amendment 58

Western Power must update its estimates of the Value of Customer Reliability to account for the findings of the Oakley Greenwood report – in particular to take account of the revised value of customer reliability estimates and the escalation method.

Required Amendment 59

Western Power must:

- amend the SAIFI incentive rate to be '$ per 0.01 SAIFI event away from the SST';
- retain the proposed SAIDI incentive rate as being '$ per SAIDI minute away from the SST'.

Required Amendment 60

Western Power must:

- adjust the Call Centre Performance incentive rate to reflect the changes to total distribution revenue set out in this Draft Decision;
- apply separate incentive penalty and reward rates to the Call Centre Performance incentive, so as to evenly span the rewards and penalties across the relevant units of difference between the PoE 50 per cent SST and the PoE 97.5 per cent lower performance bound, and the PoE 50 per cent SST and the PoE 2.5 per cent upper performance bound, respectively.

Required Amendment 61

The D-factor scheme must be removed from the proposed revised access arrangement.

Required Amendment 62

The current adjustment mechanism in relation to the recovery of deferred revenue must be retained in the proposed revised access arrangement with the deferred amounts of revenue to be updated to:

$48.6 million ($ as at 30 June 2012) for transmission services; and

$365.2 million ($ as at 30 June 2012) for distribution services.

Required Amendment 63

The proposed revised access arrangement must be amended to remove the proposed change to the treatment of depreciation in establishing the opening capital base for the fourth access arrangement.

Required Amendment 64

The Authority requires that clause 3.6 be amended as set out in paragraph 1426 above.

Required Amendment 65

Clause 18.1(a)(i) and 18.2(a)(i) must be amended as set out in paragraph 1448 above.

Required Amendment 66

An amendment is required to the electricity transfer access contract to reflect the amendments set out in paragraph 1498 above.

Required Amendment 67

An amendment is required to the electricity transfer access contract to include a clause requiring Western Power to pay interest on cash security deposits provided by users.

Required Amendment 68

The applications and queuing policy must be amended to include an express requirement for Western Power to act reasonably in deeming that an application has been withdrawn.

Required Amendment 69

Clause 20.4 of the applications and queuing policy must be amended to include the following:

"Nothing in this clause limits the matters that may be the subject of an access dispute.".

Required Amendment 70

The applications and queuing policy must include specific reference to the Price List in relation to the relevant fees.

Required Amendment 71

To ensure the applications and queuing policy is consistent with sections 2.10 and 2.11 of the Access Code, the applications and queuing policy must provide for an applicant to have an application treated independently of any other application. To give effect to this requirement:

- clauses 24.2 and 24.3 must be amended to provide for an applicant to opt out of the competing applications group process before that process commences and for the application to be treated as an application for an applicant-specific solution; and
- clause 24.5 be amended so that if an applicant does not reach agreement with Western Power on a preliminary access offer as part of the competing applications group process, the application is not deemed to be withdrawn but is to be treated as an application for an applicant-specific solution.

Required Amendment 72

The mechanisms and processes relating to the competing applications group must be more clearly defined by setting out:

- how competing applications in a "competing applications group" will be processed;
- how timing of network augmentations will be coordinated with the applications;
- how the competing applications group concept will operate; and

- what happens when an offer to all members of a competing applications group is conditional on acceptance by all applicants.

Required Amendment 73

Ttimelines for applicant-specific solutions must be stated in line with the timelines for competing application groups.

Required Amendment 74

Clause 18.2A(b) must be amended to state that Western Power must provide a response letter to applicants within 20 business days or, if not all the information is available within that timeframe, provide the applicant with as much information as possible within 20 business days and an estimated time, being not greater than 20 business days, of when the balance of outstanding information will be provided.

Required Amendment 75

The applications and queuing policy must be amended to include an obligation for Western Power to provide potential applicants with all commercial and technical information reasonably requested, and subject to any reasonable confidentiality requirements, at the pre-enquiry stage.

Required Amendment 76

The applications and queuing policy must be amended to include arrangements to enable :

- a 'supplier of last resort' as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and

- a 'default supplier' under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations (5.7(g)).

Required Amendment 77

The proposed revised access arrangement should be amended to incorporate the drafting amendments set out in paragraph 1596.

Required Amendment 78

The proposed revised access arrangement must be amended to delete all reference to the proposed distribution low voltage scheme.

Required Amendment 79

The Distribution Headworks Methodology and Contribution Policy must clarify how revenue offsets are calculated and how they are taken account of when determining headworks contributions.

Required Amendment 80

The Distribution Headworks Methodology must include a copy of the relevant price lists together with an explanation of any significant changes to those charges compared with the previous period.

Appendix 2: Public Submissions Received

Submissions were received from the following parties prior to the closing date:

- Alinta Energy (Australia) Pty Ltd
- Mr Martin Anda
- Mr David Bryant
- Denmark Community Windfarm Ltd
- Department of Commerce – Energy Safety
- Finbar Group Limited
- Goldfields-Esperance Development Commission
- Griffin Power Pty Ltd
- Landfill Gas and Power Pty Ltd
- Lend Lease
- Moonies Hill Energy Pty Ltd
- National Electrical and Communications Association
- Pacific Hydro Pty Ltd
- Professor Peter Wolfs
- Professor Syed Islam
- Silver Spring Networks Inc
- Sustainable Energy Association of Australia Inc
- Sustainable Energy Now Inc
- Synergy
- TESLA Corporation
- The Western Australian Farmers Federation Inc
- TPE Services
- Verdant Vision
- Verve Energy
- Western Australia Major Energy Users (WAMEU)
- Western Power
- Wind Prospect WA Pty Ltd

The Authority decided to accept late submissions which were received from the following parties:

- Chamber of Commerce and Industry WA
- ERM Power Limited
- LandCorp
- Office of Energy

- Perth Energy
- Property Council of Australia
- Water Corporation
- Mr Andrew Went
- Western Australian Local Government Association

Appendix 3: Target Revenue Calculation (Revenue Model)

The target revenue calculation (revenue model) sets out the Authority's determination and, in the event of inconsistency, the numbers in the calculation prevail over any other statement of these values in this decision.

The numbers in the revenue model are shown to 3 decimal places.

Due to size and formatting, this Appendix is provided as a separate document to this Draft Decision and is available from the Authority's website.[393]

[393] Economic Regulation Authority website: http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

Appendix 4: Evaluating alternative options for the SSAM

1. This Appendix provides a quantitative analysis of the performance of two alternative Service Standard Adjustment Mechanism (**SSAM**) formulas, compared to the existing and proposed formulas, using the System Average Interruption Duration Index (**SAIDI**) measure for the Central Business District (**CBD**) as an example.

2. The SSAM rewards or penalties are derived from the product of the 'service standard difference' (**SSD**) in each year, and the SSAM incentive rates. The SSD is the difference between actual performance on a measure and the target performance.

3. The SSD in the current access arrangement is calculated as follows:

   SSD2009/10 = (SSB2009/10 – SSA2009/10)

   SSD2010/11 = (SSB2010/11 – SSA2010/11) - (SSB2009/10 – SSA2009/10)

   SSD2011/12 = (SSB2011/12 – SSA2011/12) - (SSB2010/11 – SSA2010/11)

   Where:

   SSD_t is the service standard difference in year t;

   SSB_t is the service standard benchmark in year t; and

   SSA_t is the actual service performance in year t.

4. The existing SSAM SSD implied that only an incremental improvement in net performance, compared to that in the year before, was rewarded. Under this approach, performance in any year may be above the SSAM target, but a penalty still applied that year – if the net performance is less than the year before. Conversely, performance may be below the target, but still receive a reward, provided that the net performance shortfall to the target was less than the year before. For example, the formula that applied in the current access arrangement for the second and subsequent years was:

   $SSD_t = (SST_t – SSA_t) - (SST_{t-1} – SSA_{t-1})$

5. Western Power's proposed method for AA3 on the other hand aims to institute a simple difference in each year to calculate the SSD:

   $SSD_t = (SST – SSA_t)$

6. The Authority has considered two potential alternative formulas as a means to overcome the shortcomings of the above.

7. The first alternative includes an 'attenuation factor' (**AF**) in the existing formula that conditions the influence of the second term:

   $SSD_t = (SST_t – SSA_t) – \mathbf{AF} * (SST_{t-1} – SSA_{t-1})$

   This is referred to as the ***factor*** approach.

8. The second alternative accepts the proposed approach as the formula for the SSAM – but with a proviso that the SST be updated every year to incorporate the most recent 12 months of historic data (recalls that the SST is set on the basis of the most recent available 60 months of data). This is referred to as the ***ratchet*** approach.

Value of customer reliability

9. The Authority notes that the value of customer reliability (**VCR**) of a minute of interruption in the Perth CBD is estimated at around $70,000.[394] This is a 'transfer benefit' derived from surveys of Victorian network consumers' damage costs arising from outages, calibrated to Western Australia. This value is used in setting the SAIDI incentive rate. This value of saving one minute of SAIDI is utilised in what follows.

10. An investment to improve the performance on SAIDI by one minute each year will result in a benefit to CBD consumers of $70,000 annually. A life for the investment of 25 years may be assumed (the results that follow are not sensitive to this life, the choice of measure, or to the value of a SAIDI minute).

11. As a base case, it is assumed that CBD consumers have a discount rate of 15 per cent – a common hurdle rate for business. This discount rate may be considered low. Consumers' willingness to invest in non-core business activities – such as energy efficiency – may be as high as 50 per cent or more. The results are sensitive to this discount rate. That said, the present value (**PV**) to a user of the VCR at 15 per cent over 25 years of a minute of SAIDI improvement is $520,000.

Efficient investment in VCR

12. Consideration of economic efficiency suggests that Western Power should invest in reliability so long as the cost of an investment is less than or equal to the benefit of that investment.[395] The benefit is the VCR.

13. The cost will be the value of the investment made by Western Power (which would be rolled into the asset base, then remunerated at WACC each year), plus the value of any service standard incentive (which is a 'transfer' from consumers to Western Power – that occurs in the first year of the following AA). The incentive could be set to recover half of the PV of the VCR. In this case, for:

    - an investment which is costless to Western Power – the cost to consumers would be the (half of the PV of the VCR) service standard incentive only – in this case the benefit to consumers would be double the cost to them;
    - an investment which costs Western Power half of the PV of VCR – the cost to the consumer is half of the PV of the VCR rolled in to the asset base (as Western Power's investment cost, which is remunerated at WACC), plus the (half of the PV of the VCR) service standard incentive transfer from consumers to Western Power – in this case the benefit to consumers would be exactly matched by the cost to them;

[394] Specifically, the estimated damage cost in $/MWh is applied to the average MWh lost in an outage of one minute duration to determine the value of an annual SAIDI minute.

[395] The 'marginal' investment would be that investment where the cost just equals the benefit, satisfying the efficiency criterion that investments are undertaken up to the point where the marginal cost of investment equals the marginal benefit.

- an investment which costs Western Power the full amount of the PV of VCR – the cost to the consumer is the full PV of the VCR rolled in to the asset base (as Western Power's investment cost, which is remunerated at WACC), plus the (half of the PV of the VCR) cost of the service standard incentive transfer from consumers to Western Power – in this case the cost to consumers exceeds the benefit to them by a factor 1.5.

14. Based on the above, assuming projects to save a SAIDI minute are normally distributed, then on average, the projects initiated by Western Power will have a cost equal to the PV of the VCR. That is, projects that cost less will balance out projects that cost more. However, half of the projects would not be efficient, as the cost to the customer of those projects would exceed the benefit to them.

15. On this basis, the incentive could be set at 30 per cent of the PV of the VCR, say – as this would reduce the likelihood that a project is inefficient. This would still maintain some incentive for Western Power to undertake projects which are zero to low cost (and hence which don't deliver a large return to it), but which have a VCR value to customers and thus a high net benefit to the economy.

16. In what follows we use the 30 per cent of the PV of the VCR as the incentive rate. The overall conclusions in what follows are not very sensitive to this assumption..

Relative performance of the different SSAM formulas

17. The relative performance of the different approaches in delivering the required 30 per cent PV of the VCR is set out at Table 123 (see row 1 for the PV of the VCR, and row 2 for the 30 per cent value of the PV of the VCR).

18. It may be seen that:

    - row 5 – the current access arrangement formula tends to under-reward significantly for investments made at the start of the AA, but provides an appropriate amount towards the end;
    - row 9 – the proposed simple formula tends to over-reward significantly for investments made in any year of the AA;
    - row 12 – the 'factor' formula can be tuned to minimise the absolute difference between the actual incentive and the target incentive – see row 10 for the optimal factors;
    - row 15 – the 'ratchet' formula tends to over-reward, but attenuates the reward in line with the desired outcome.

19. The 'factor' formula can thus be made to be superior to the ratchet 'formula', once it is 'tuned' (Table 124). However, the exact tuning is sensitive to the required value of the incentive (which may vary with the PV of the VCR or with the 'optimal' proportion of the PV of the VCR). With a consumer discount rate of 50 per cent (refer paragraph 9 above), the PV of the VCR falls. In this case:

    - The 'factor' would need to increase to reduce the rewards to be commensurate with the PV of the VCR (assuming as before, that we are targeting an incentive of 30 per cent of PV of the VCR).
    - The 'ratchet' approach would over-reward significantly in this instance.

Table 123 SSAM mechanism relative performance

Row no.	Item	Investment undertaken in year of access arrangement					Sum of absolute differences to target
		Year 1	Year 2	Year 3	Year 4	Year 5	
1	**PV of VCR of saving 1 minute SAIDI**	$520,364	$450,364	$389,494	$336,564	$290,538	
2	**Target incentive of 30% of PV of VCR**	$156,109	$135,109	$116,848	$100,969	$87,161	
3	**Current Access Arrangement formula result**						
4	PV of incentive if investment made in year	$70,000	$76,210	$82,664	$68,677	$96,243	
5	Difference to target	-$86,109	-$58,899	-$34,185	-$32,292	$9,081	$220,566
6	**Western Power 'simple' formula result**						
7	PV of incentive if investment made in year	$311,120	$287,052	$267,107	$159,180	$238,631	
9	Difference to target	$155,011	$151,942	$150,258	$58,211	$151,470	$666,893
8	**Factor formula result**						
10	Year 'factor'	0.64	0.64	0.64	0.64	0.64	
11	PV of incentive if investment made in year	$124,683	$119,895	$116,759	$115,179	$115,062	
12	Difference to target	-$31,426	-$15,214	-$89	$14,210	$27,901	$88,840
13	**Ratchet' formula result**						
14	PV of incentive if investment made in year	$194,216	$182,775	$172,007	$161,874	$103,531	
15	Difference to target	$38,107	$47,666	$55,159	$60,904	$16,369	$218,205

Source: Authority estimates

Table 124 Comparison of alternative formulas

Existing formula $SSD_t = (SST_t – SSA_t) - (SST_{t-1} – SSA_{t-1})$	**Proposed formula** $SSD_t = (SST_t – SSA_t)$	**'Factor' formula** $SSD_t = (SST_t – SSA_t) – AF * (SST_{t-1} – SSA_{t-1})$	**'Ratchet' formula** $SSD_t = (SST_t – SSA_t)$ with annual SST setting
Rewards only absolute incremental improvements year to year	Incremental year to year deterioration can be rewarded, provided that SSAt < SSTt	**Some reward** for incremental deterioration still possible, but attenuated	Incremental deterioration can be rewarded, provided that SSAt < SSTt, but SSTt gets tighter each year
Can reward < SST performance if there is incremental improvement	Must perform better than SST to be rewarded	Attenuates reward for < SST performance	**Must perform better than SST** to be rewarded
Under-rewards compared to 0.3 VCR, except for investments in last year	Over-rewards compared to 0.3 VCR	Can be 'tuned' to deliver the **closest reward compared to 0.3 VCR**, both on average and absolutely	Rewards at rate closer to 0.3 VCR on average, but still tends to over-reward
Some dis-incentive to invest early in the AA, as the rewards to Western Power is greater for investments undertaken late in the AA	Provides a strong incentive to initiate improvements early in the AA, as this maximises the value of the incentive to Western Power	**Reduced dis-incentive** to initiate improvements early in the AA	Reduced incentive to initiate improvements early in the AA remains
Avoids incentives to defer a late AA improvement to next AA, as highest value to Western Power is late in the AA	Provides an incentive to defer a late AA improvement until the next AA, as Western Power gets a greater reward early in the AA	**Avoids adverse incentives** to defer a late AA improvement to next AA	Provides an incentive to defer a late AA improvement until the next AA
Provides certainty of SST over AA	Provides certainty of SST over AA	Provides **certainty** of SST over AA	Uncertain SST over AA
Five yearly regulatory oversight and review	Five yearly regulatory oversight and review	**Five yearly** regulatory oversight and review	Annual administrative regulatory oversight and review

Note: Bolded comments highlight the alternative formula with the best outcomes

Appendix 5: Treatment of Equity Raising Costs

The Authority considers that an allowance for the transactions costs of raising equity is justified where an adjustment is required to maintain the debt to equity ratio.

The accepted hierarchy for capital raising is:

- retained earnings (and by corollary dividend reinvestment);
- debt;
- new equity injections.

Retained earnings and dividend reinvestment

The level of retained earnings relates to the dividend the business is expected to pay – retained earnings are after-tax profits, less dividends.

The Authority considers that a payout ratio of 70 per cent of after tax profits is a typical benchmark for the dividend payout ratio, leaving 30 per cent of after tax profits as retained earnings. The 70 per cent rate is the same as the payout ratio F utilised for the calculation of the WACC.

Generally, it is assumed that retained earnings are costless to the firm.[396]

Evidence from recent data analysed by the Authority covering six utilities suggests that around 25 per cent of annual dividends, on average, are subject to reinvestment plans (Table 125).

The AER has previously adopted a cost for dividend reinvestment of 1 per cent – although this appears to be an assumption.[397] The Authority's view is that many investors simply 'tick the box' for dividend reinvestment plans, implying that dividend reinvestment is virtually costless to the business.

For these reasons, the Authority assumes a zero cost for dividend reinvestment, with 25 per cent of dividends reinvested.

[396] See, for example, Handley J. C. 2009, *A note on the costs of raising debt and equity capital: report prepared for the Australian Energy Regulator*, www.aer.gov.au, p.18.

[397] Australian Economic Regulator 2009, *Final Decision – Transend Transmission Determination 2009-10 to 2013-14*, p. 110.

Table 125 Dividend re-investment ratios

Company Name	Year	Dividends ($m OD)	Reinvested ($m OD)	Re-invest. Ratio	5 Year Av.
Origin Energy	2011	226,000,000	61,000,000	26.99%	
	2010	220,000,000	65,000,000	29.55%	
	2009	218,000,000	19,000,000	8.72%	22.74%
	2008	201,040,000	45,000,000	22.38%	
	2007	158,654,000	41,350,000	26.06%	
AGL Energy	2011	143,000,000	61,900,000	43.29%	
	2010	125,500,000	36,400,000	29.00%	
	2009	119,900,000	58,700,000	48.96%	29.38%
	2008	112,700,000	28,900,000	25.64%	
	2007	-	-	No plan	
SP Ausnet	2011	131,400,000	74,800,000	56.93%	
	2010	157,400,000	46,900,000	29.80%	
	2009	124,000,000	26,600,000	21.45%	21.63%
	2008	-	-	No plan	
	2007	-	-	No plan	
DUET Group	2011	-	-	No plan	
	2010	84,709,000	27,072,206	31.96%	
	2009	82,277,000	18,935,563	23.01%	18.56%
	2008	106,420,000	18,885,523	17.75%	
	2007	92,136,000	18,500,000	20.08%	
Spark Infrastructure Group	2011	-	-	No plan	
	2010	-	-	No plan	
	2009	68,178,378	25,226,000	37%	7.40%
	2008	-	-	No plan	
	2007	-	-	No plan	
Envestra Limited	2011	77,500,000	44,300,000	57.16%	
	2010	73,000,000	42,300,000	57.95%	
	2009	75,800,000	32,100,000	42.35%	51.01%
	2008	81,700,000	34,600,000	42.35%	
	2007	77,800,000	43,000,000	55.27%	
All six companies					**24.5%**

Source: Annual reports

Equity raising costs

It is generally accepted that the average cost of 'seasoned equity offerings' (**SEO**) is around 3 per cent. This derives from work in 2004 by the Allen Consulting Group, which recommended:[398]

> If a rights issue (or other SEO) were found to be required, ACG recommends a benchmark transaction cost of 3%, adding the amount of SEO transaction costs to the capital base (RAV) and depreciating over the life of the assets purchased with funds raised by the notional, benchmarked SEO.

Shareholders, if they accepted that a major investment was warranted, could accept a lower dividend, for a period, as a means to inject equity – given that this has the lowest financing cost. This could be rational.

- However, many investors seek dividend stability.
- Further, decisions by investors to invest additional funds in the business necessarily would be made within the context of their overall portfolios – some investors might view a dividend reduction as inconsistent with their risk preferences. Finally, any reduction in dividends would potentially waste franking credits, which are important for some investors.
- The Authority considers that given the evidence for dividend reinvestment comprising 25 per cent of dividends (see above), and given that many investors would prefer to make an explicit decision on whether to re-invest dividends in a business, that any additional capital raising requirement that is over and above standard re-investment rates has the nature of SEO, and hence should be charged at the higher SEO cost of raising equity.

Finally, Allen Consulting Group imply that some leeway in the debt to equity ratio might also be considered:[399]

> There will be a limit to the degree to which a company can increase its gearing to undertake such projects, and at the same time maintain financial viability. Regulators must ensure that the revenue target allowance provides for the regulated utility to maintain its financial viability and a notional investment grade credit rating...
>
> There can be instances of regulated businesses where incremental capital expenditure is very lumpy and a significant equity injection is necessary, as the notional capital structure would be breached for a considerable period (or expected debt covenants associated with the notional capital structure would otherwise be breached). However, ACG is not aware of any specific Australian case in which an SEO raising has been clearly justified for a regulated asset.

However, the Authority considers that the benchmark regulatory model assumes a fixed debt to equity ratio in order to reflect the returns that would accrue to a service provider in a commercial enterprise with a similar nature and degree of non-diversifiable risk as the regulated entity. For such an entity, where a large lumpy capital investment is being undertaken that cannot be financed out of

398 The Allen Consulting Group 2004, *Debt and Equity Raising Transactions Costs*, www.aer.gov.au, p. 69.

399 The Allen Consulting Group 2004, *Debt and Equity Raising Transactions Costs*, www.aer.gov.au, p. 62 and p. 69.

retained earnings or standard rates of dividend reinvestment, then new equity raising is justified, with the attendant costs.

Tax deductibility of equity raising costs

It is assumed that where equity is raised, an additional amount of equity is raised to cover the SEO transactions costs of raising that equity.[400]

Certain parts of the equity raising transactions costs may be deductible for tax purposes in the year of the equity raising – including legal fees, accountants' fees and prospectus costs.[401] However, the Authority considers that these costs are small and hence may be ignored for the purposes of the revenue modelling.

On this basis, the total amount of the SEO costs is added to the asset base, and depreciated over the life of the assets.

Summary of the Authority's position

The Authority considers that the equity share should be maintained at 40 per cent of the estimated regulated asset base, taking into account that:

- dividends should be assumed to be paid at the benchmark payout ratio of 70 per cent – consistent with the Authority's WACC analysis;
- the residual of retained earnings of 30 per cent of after-tax profits should be assumed to be available at zero cost;
- 25 per cent of dividends should be treated as being reinvested on a 'tick the box' basis, with a zero cost of raising equity applied to these funds;
- any further required equity should be raised at the Seasoned Equity Offering cost of 3 per cent – with these costs added to the asset base and depreciated over the life of the assets.

[400] See for example Grant Thornton 2010, *Technical Accounting Alert: Cost of an Initial public offering*, www.grantthornton.com.au/files/ta_alert_2010-28_costs_of_an_initial_public_offering.pdf.

[401] Ibid.

Appendix 6: Consultant Reports Commissioned by the Authority

The following consultant reports[402] were commissioned by the Authority:

- Geoff Brown and Associates, Technical Review of Western Power's Proposed Access Arrangement for 2012-2017, March 2012
- BDO, Agreed Upon Procedures Engagement-Western Power's Access Arrangement for the South West Interconnected Network, March 2012

---

[402] Reports are available from the Economic Regulation Authority website: http://www.erawa.com.au/3/1181/48/_western_powers_proposed_revised_access_arrangemen.pm

Appendix 7: Terms / Abbreviations

Term	Definition
AA1	Access Arrangement for the first period (commencing 1 July 2007)
AA2	Access Arrangement for the second period (commencing 1 March 2010)
AA3	Access Arrangement for the third period (expected to commence 1 July 2012)
AA4	Access Arrangement for the fourth period (expected to commence 1 July 2017)
ACCC	Australian Competition and Consumer Commission
Access Arrangement Information	Western Power's Access Arrangement information
Access Code	*Electricity Networks Access Code 2004*
ACG	Allen Consulting Group
ACT	Australian Competition Tribunal
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AF	Attenuation Factor
APR	Annual Planning Report
AQP	Application and Queuing Policy
ASX	Australian Stock Exchange
Authority	Economic Regulation Authority
AWOTE	Average Weekly Ordinary Time Earnings
BDO	BDO Chartered Accountants
CAIDI	Customer Average Interruption Duration Index
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CBRM	Condition Based Risk Management

CCI	Chamber of Commerce and Industry
CEG	Competition Economists Group
CGS	Commonwealth Government Securities
CPI	Consumer Price Index
Current access arrangement	Western Power's access arrangement for the second access arrangement period
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DHM	Distribution Headworks Methodology
DLVCS	Distribution Low Voltage Connection Scheme
DNS	Distribution Network Service Provider
E&Y	Ernst & Young
EGWW	Electricity, Gas, Water and Waste Services
ERA	Economic Regulation Authority
ERM	ERM Power Ltd
ESC	Essential Services Commission of Victoria
ETAC	Electricity Transfer Access Contract
ESCOSA	Essential Services Commission of South Australia
GBA	Geoff Brown & Associates
GHD	GHD Australia
GSL	Guaranteed Service Level
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
IAM	Investment Adjustment Mechanism
ICRC	Independent Competition and Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
IT	Information Technology
LAD	Least Absolute Deviation
MAIFI	Momentary Average Interruption Frequency Index
MRP	Market Risk Premium

MWEP	Mid West Energy Project
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERA	NERA Economic Consulting
NFIT	New Facilities Investment Test
NPV	Net Present Value
NQ&RS Code	*Electricity Industry (Network Quality and Reliability of Supply) Code 2005*
POE	Probability of Exceedence
Proposed revised access arrangement	Western Power's proposed revised access arrangement for the third access arrangement period
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QCA	Queensland Competition Authority
RBA	Reserve Bank of Australia
RPIP	Rural Power Improvement Program
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEO	Seasoned Equity Offerings
SFG	Strategic Finance Group
SKM	Sinclair Knight Mertz
SSAM	Service Standards Adjustment Mechanism
SSB	Service Standard Benchmarks
SSD	Service Standard Difference
SST	Service Standard Target
SUPP	State Underground Power Project
SWIN	South West Interconnected Network

TEC	Tariff Equalisation Contributions
the Act	*Electricity Industry Act 2004*
TUOS	Transmission Use of System
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WAGN	Western Australia Gas Networks
WALGA	Western Australian Local Government Association
WAMEU	Western Australian Major Energy Users
WATC	Western Australian Treasury Corporation
WEM	Wholesale Electricity Market
WPI	Wage Price Index

Appendix 8: Confidential Annexure

Not published.